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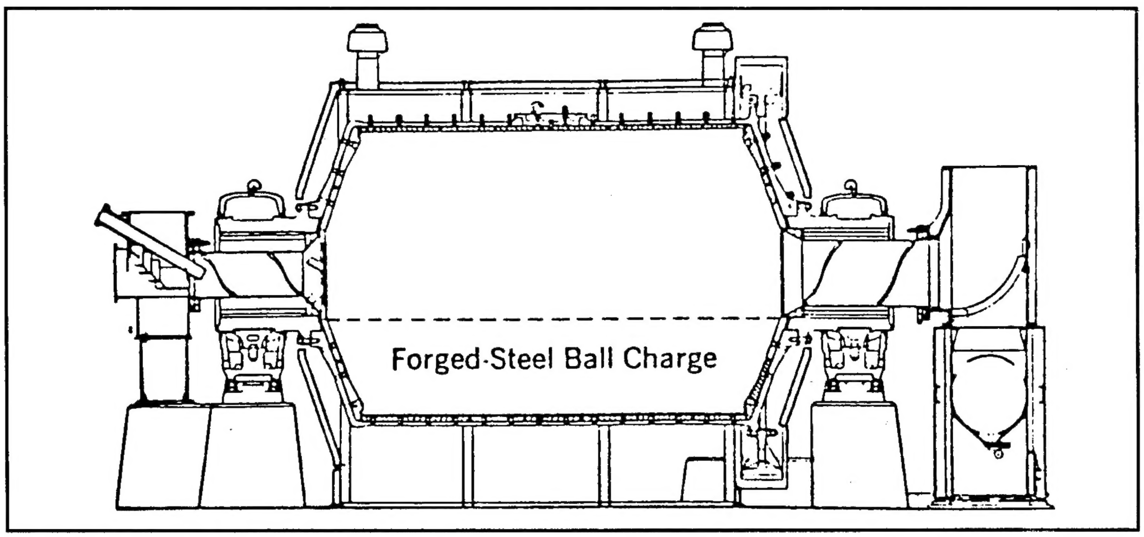
Screening and Costing Models for New Pulverized-Coal Heating Plants

An Integrated Computer-Based Module for the Central Heating Plant Economic Evaluation Program (CHPECON)

by
Robert Sheng, John A. Kinast, Richard Biederman, Christopher F. Blazek, and Mike C.J. Lin



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The model is divided into two parts. A preliminary screening model contains options for evaluating new heating plants and cogeneration facilities fueled with pulverized coal, as well as the previous options. A cost model uses the entries provided by the screening model to provide a conceptual facility design, capital (installed) costs of the facility, operation and maintenance costs over the life of the facility, and life-cycle costs. Using these numbers the model produces a summary value for the total life-cycle cost of the plant, and a levelized cost of service.

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Foreword

This study was conducted for the Assistant Chief of Staff for Installation Management (ACS(IM)), Directorate of Facilities and Housing, under the Coal Conversion Studies Program, which is administered by the Energy Policy Directorate of the Office of the Assistant Secretary of Defense, Production and Logistics, Energy Policy (OASD P&L/EP). Funding was provided under the Reimbursable Work Unit "Pulverized Coal–Boiler Option"; Military Interdepartmental Purchase Request (MIPR) no. W56HZV-89-AC-01, dated 10 April 1991. The technical monitor was Quaiser Toor, DAIM-FDF-U.

The work was performed by the Industrial Operations Division (UL-I) of the Utilities and Industrial Operations Laboratory (UL), U.S. Army Construction Engineering Research Laboratories (USACERL). The Principal Investigator is Dr. Mike C.J. Lin, CECER-UL-I. Robert Sheng, John A. Kinast, Richard Biederman, and Christopher F. Blazek are associated with the Institute of Gas Technology, Chicago, IL, which conducted a portion of this work under contract. Ralph E. Moshage is Acting Chief, CECER-UL-I, John T. Bandy is Operations Chief, and Gary W. Schanche is Chief, CECER-UL. The USACERL technical editor was Gordon L. Cohen, Technical Resources Center.

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LTC David J. Rehbein is Commander and Acting Director of USACERL, and Dr. Michael J. O'Connor is Technical Director.

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1 Introduction

Background

The 1986 Defense Appropriation Act (PL-99-190), Section 8110, directed the Department of Defense (DOD) to rehabilitate and convert oil- or gas-fired central heating plants to coal combustion wherever fuel savings could be realized. The target set by this act was to use 1.6 million short tons of coal per year over the 1985 consumption level by 1994. The language further stated that 300,000 tons of this amount should be anthracite coal, which would offset decreasing anthracite coal use in Germany resulting from U.S. Army, Europe (USAREUR) installations connecting to district heating systems. To help the Army comply with PL-99-190, the Assistant Chief of Staff for Installation Management (ACS(IM)) tasked the U.S. Army Construction Engineering Research Laboratories (USACERL) to provide technical studies and support for the Army's Coal Conversion Program.

In previous work USACERL developed a series of screening and life-cycle cost computer-based models to help the user determine where and when coal-combustion technologies can cost-effectively be implemented at Army central heating plants. These models, collectively called CHPECON (Central Heating Plant Economic Evaluation Program), are documented in a five-volume USACERL report (Lin et al. 1995). The models developed in that work addressed the renovation or retrofitting of existing plants, or the new construction of a coal-fired plant. However, an additional model is needed to evaluate the building of a new pulverized-coal plant as an economical option to others addressed by CHPECON.

Objective

The objective of this work was to develop a CHPECON module to evaluate the screening criteria and life-cycle costs of replacing an existing central heating plant with a new pulverized-coal plant.

Approach

Cost-estimating methods have been developed for building new pulverized-coal plants. The plant sizes examined in the model range between 50,000 to 600,000 lb/hr, with individual boiler sizes from 100,000 to 275,000 lb/hr of steam or high-temperature hot water (HTHW).

The program is divided into two parts: the preliminary screening model and the detailed cost model. The screening model is used to initially evaluate each plant site and boiler technology option to produce a list of the promising locations and technology options.

The new heating plant screening model is used to determine if a new coal-fired heating plant feasibly can be built to replace an existing steam plant (150 psig* saturated steam or equivalent hot water, or 250 psig saturated steam). The cogeneration screening model is used to determine if a new cogeneration steam plant is a feasible alternative for a military base heating plant. Medium-pressure (600 psig at 750 °F) or high-pressure (1300 psig at 1000 °F) plants can be analyzed. The consolidation screening model is used to determine if the installation should consolidate several individual heating plants into one central plant; it assesses whether the steam-distribution density is sufficient to consider consolidation as a viable option.

The costing model contains sections for a new heating plant, cogeneration facility (base-owned and third-party) and consolidated facility. The costing model provides conceptual facility design, capital installed costs of the conceptual facility, operational and maintenance costs over the life of the conceptual facility, and life-cycle costs.

Scope

The models developed in this work are generally applicable to industrial or large commercial-size facilities. The economic evaluation program for screening and life-cycle costs will serve as a tool to select and rank potential Army sites for coal conversion.

The life-cycle cost analysis facility within CHPECON operates the same for pulverized-coal plants as for other types of energy plants, and is not documented in this report. Documentation of the life-cycle cost analysis facility may be found in Lin et al. (January 1995).

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* psig: pounds per square inch gage.

System Requirements

The CHPECON module described in this report is implemented for use on microcomputers using an 8088 processor (or later) and running MS–DOS (Microsoft® Disk Operating System) version 2.0 or later. CHPECON requires 640 kilobytes of random-access memory. The software was written in a language compatible with dBase III Plus*, with some extensions. The program was compiled using Clipper**, which allows stand-alone operation without requiring additional utilities.

Mode of Technology Transfer

The CHPECON installation program may be obtained from the USACERL Industrial Operations Division (CECER-UL-I), 1-800-872-2375, extension 3487. The program will be transferred to Major Army Command headquarters for further distribution.

Because the DOD Coal Conversion Program has ended, no further modifications to CHPECON are planned at this time.

It is recommended that the information presented in this report be disseminated in a Public Works Technical Bulletin (PWTB).

Metric Conversion Factors

U.S. standard units of measure are used in this report. A table of metric conversion factors can be found below.

1 in.	=	25.4 mm
1 ft	=	0.305 m
1 sq ft	=	0.093 m^2
1 cu ft	=	0.028 m^3
1 cu yd	=	0.7646 m^3
1 mi	=	1.61 km
1 acre	=	4047 m^2
1 lb	=	0.453 kg
1 ton	=	907.18 kg
1 gal	=	3.78 L
1 psi	=	6.89 kPa
°F	=	(°C x 1.8) +32

* dBase III Plus is a registered trademark of Ashton-Tate.

** Clipper is a registered trademark of Nantucket Software.

2 Pulverized-Coal Boiler Technology

This chapter presents a brief overview of the technology, operation, and performance of pulverized-coal boilers.

Benefits of Pulverized-Coal Boilers

The interest in burning what is known today as pulverized coal (PC) dates as far back as 1824, when Sadi Carnot provided a critical thermodynamic analysis of the pyréolophore, an engine fired by powdered coal (Carnot, Clayperon, and Clausius 1962). Rudolf Diesel conducted his first experiments on the internal combustion engine bearing his name using pulverized coal as the primary fuel during the 1890s (Diesel 1894). At the same time, pulverized-coal firing was achieving its first real commercial success in the cement industry; Thomas Edison greatly increased efficiency and output in cement kilns by improving the firing of pulverized coal in them (Herington 1918; Dyer and Martin 1929).

From these initial applications of pulverized coal has developed the current state of the art. The technology was developed largely during the 20th century through empirical research rather than theoretical. Early steam boilers using what then was known as powdered coal were first built during the 1910s and 1920s (Anderson, 2 March 1920; *Power,* 7 September 1920).

Reasons for the initial interest in pulverized coal—and its continued utilization—are many. The first is that coal is widely available, a point even more important now than at the turn of the century due to potential disruptions of the imported oil supply. However, oil and gas combustion are more easily controlled and regulated than is burning large pieces of coal. This is shown by the fact that the range of capacity turndown for gas and oil boilers is twice or more that of coal-fired stoker boilers. If coal can be turned into a form more like gas, then it can approach the ease of operation and wide turndown capabilities of gas. This is the premise of the coal gasification processes that have been researched, and is also the rationale for using pulverized coal.

In general terms, pulverizing coal turns it into a fine powder that can be carried along in air streams much as natural gas. Because of its powdery form, the coal spreads more uniformly throughout an air stream. This concept is opposite of the situation found in other coal technologies, where air is moved through or along the surface of a bed of coal. The grinding also increases the surface-to-weight ratio, exposing more surface, which in turn allows quicker and more complete burning. The reduced particle size also keeps the ash in a similar, finely distributed form.

From practical experience, boilers using PC can have more closely spaced heat exchanger tubes and smaller overall sizes because of their high combustion intensity and because they do not need a large bed for spreading the coal to achieve combustion. The similarity of PC to natural gas can also be seen in comparing the types of flames observed. In general, PC burns at a temperature and intensity closer to natural gas than to stoker boilers or other coal systems. It is also apparent in the turndown range of 4:1 or more for PC as compared to 8:1 for gas and 2:1-3:1 for stoker boilers.

PC boilers also can be built to much larger sizes than is feasible with other coal boilers because the upper practical bed size for conventional coal technologies is many times smaller than for PC boilers. However, PC boilers have practical lower size limits that are larger than for other coal boilers. This is due in part to the minimum size of practical, cost-effective pulverizers and related equipment. Pulverizers play an important role in defining the lower size limits because pulverized coal is not stored, but created as needed.

As a result of the greater size range and controllability, the PC boiler has been the concept of choice for electricity-generation facilities. This attention by the electric utilities has produced a great deal of experience and background in the field, and makes the PC boiler a strong competitor, as long as it fits in the practical size range.

PC Boiler Operation

Pulverized-coal boiler technology has been fully commercialized for decades. Steam-generating capacities as low as 60,000 lb/hr (for small industrial units) to over 10 million lb/hr (for utility applications) have been installed. PC systems provide (1) higher thermal efficiency (2) least coal-feed preparation, and (3) low excess air requirements.

In a PC-fired boiler, coal is ground to fine particles—typically 70 percent through 200 mesh. The pulverized coal is carried in an air stream to the burners, where it is burned in total suspension. The coal/air mixture burns much the same as oil or gas.

Two principal systems—the bin system and the direct-firing system—have been used for processing, distributing, and burning pulverized coal. The direct-firing system is being installed almost exclusively in recent projects. A typical direct-firing system is shown in Figure 1. Major components are (1) coal feeder, (2) primary/secondary air blower or exhauster, (3) air heater, (4) pulverizer and classifier, (5) coal-air conveying lines, (6) burners, and (7) boiler.

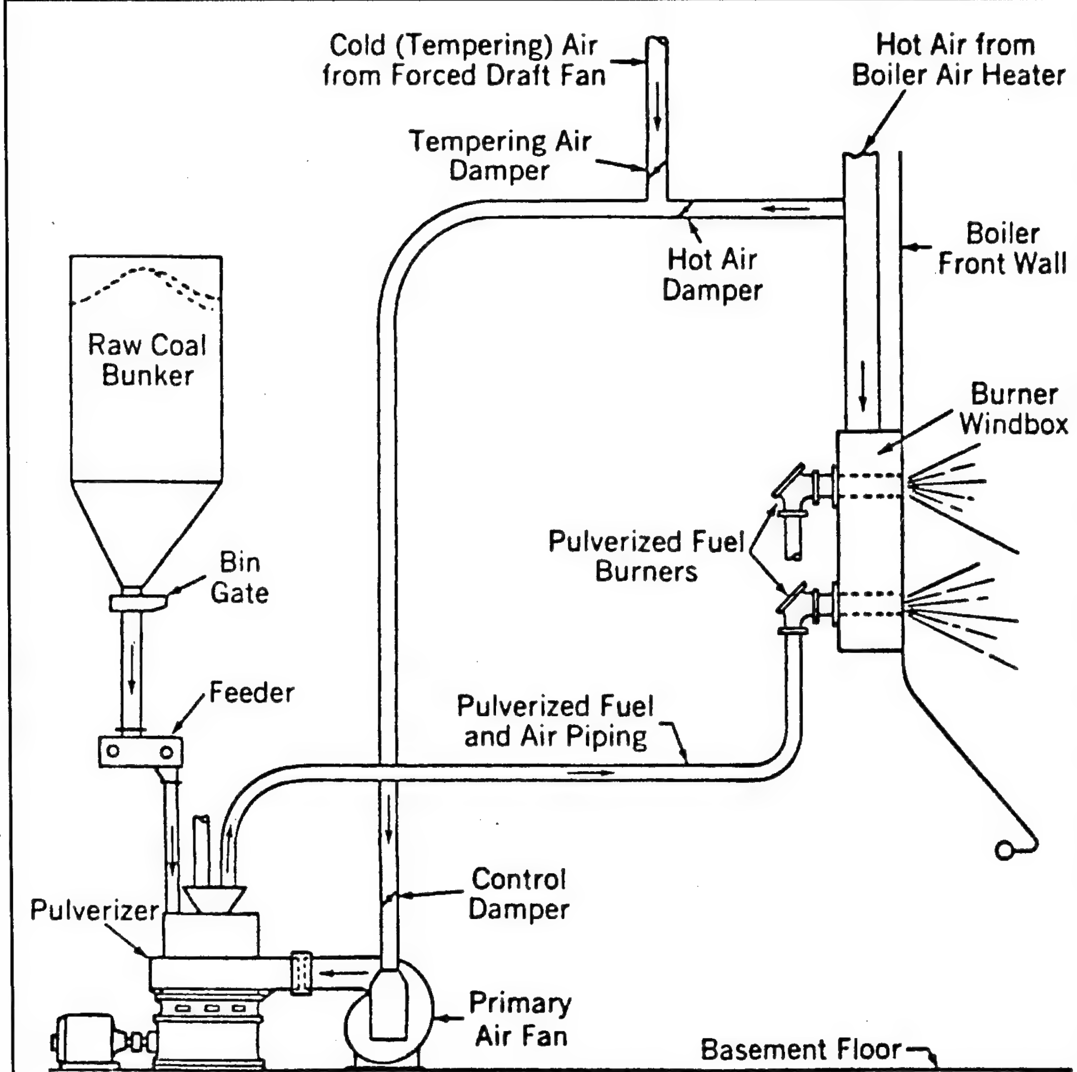
Raw coal is fed from overhead bunkers to the pulverizer by the coal feeder. Two basic types of feeders are commonly used—the volumetric feeder and the gravimetric feeder. The volumetric feeder feeds coal by volume. Its disadvantage is that the bulk density of coal varies resulting in variation in the weight of coal fed and, thus, variation in total energy input to the furnace. The gravimetric feeder is both a weight flowmeter and a feeder. It compensates for variations in bulk density of the coal feed, but does not compensate for energy input variations that result from changes in ash content of the coal.

Coal is pulverized and dried in the pulverizer, and then conveyed to the burners. A portion of the combustion air, known as *primary air*, is used for drying and pneumatic conveying of the pulverized coal. The remainder of the combustion air is introduced at the burners, and is known as *secondary air*. For pressurized pulverizers, the primary-air fan, located on the inlet side of the pulverizer, forces air through the pulverizer and then to the burners.

The fan handles clean air and is not subjected to abrasion by the pulverized coal. Therefore, a high-efficiency fan with efficient rotor design and high tip speed can be used. If the pulverizer is operated under negative pressure, the fan or exhauster must handle PC-laden air. The exhauster housing must be designed to withstand higher pressure in case of an explosion within the fan. Furthermore, the exhauster is subject to excessive wear from the entrained coal particles. This latter fan design is limited to heavy construction or special protective surface coatings, and lowers the mechanical efficiency of the fan.

The coal feed rate to the pulverizer is controlled by the boiler load demand. The primary air supply is adjusted to the coal feed rate to provide the air required for drying and moving the pulverized coal, and to maintain a predetermined primary air-to-coal ratio. Drying is accomplished in the pulverizer by the preheated primary air.

Temperature of the coal-air mixture is monitored and controlled by varying the degree of air preheating. Low temperatures indicate insufficient drying of coal, which may result in plugged conveying lines. However, high temperatures may lead to a hazardous condition because of excessively dried coal. Adequate air flow rate must



(Source: Babcock and Wilcox, Inc. 1972, p 9-4.)

Figure 1. Direct-firing system for pulverized coal.

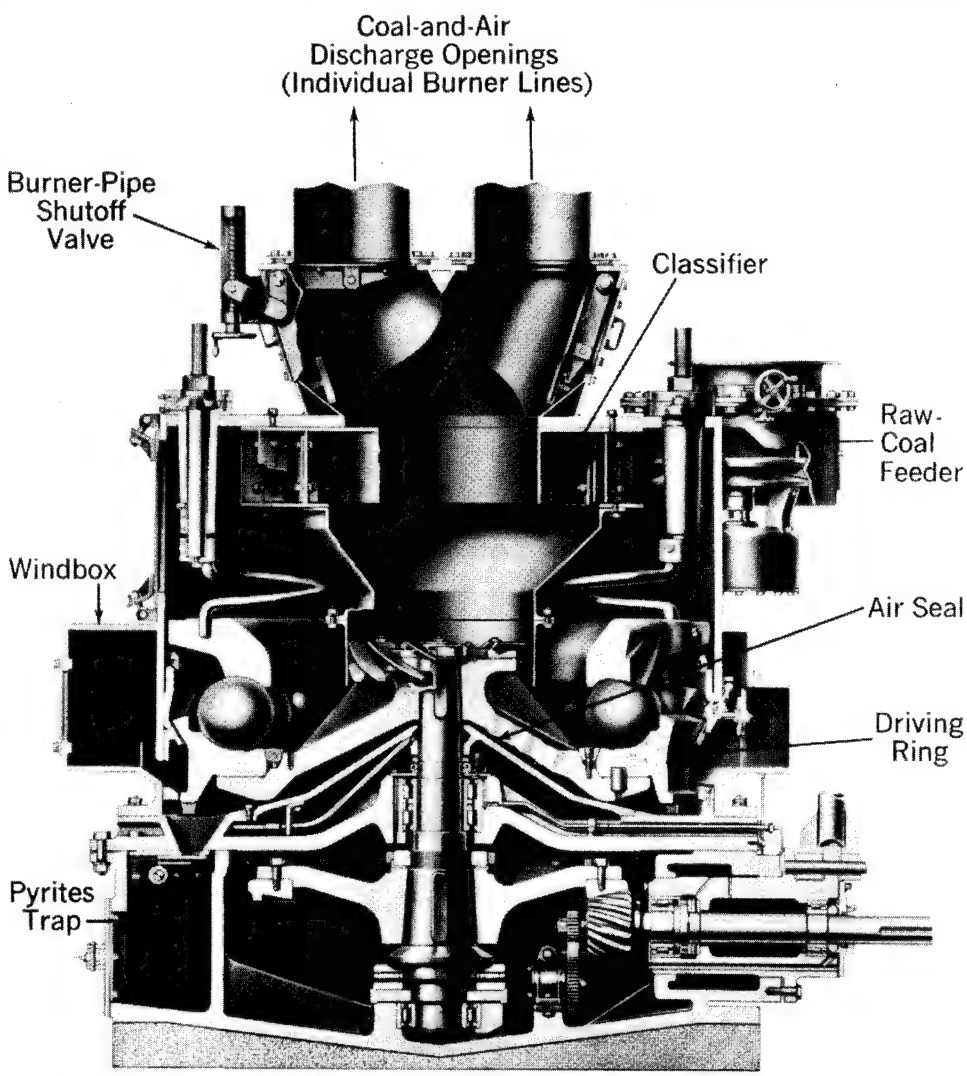
also be maintained to produce high enough air velocity to convey the coal without settling—typically 3000 ft/min for horizontal and 2200 ft/min for vertical burner pipes.

Load is changed on PC units by varying fuel and air feed, and is limited by the ability to maintain a stable flame at given conveyance velocities in the coal pipes. As the stable lower delivery limit is reached on multiple pulverizers, one pulverizer can be removed from service and load further reduced using the remaining pulverizers. Maintaining flame stability at lower delivery rates may require the use of auxiliary fuel.

The pulverizer, an electric-motor-driven machine, crushes coal either (1) between rotating balls and a race, (2) between a roller and a bowl, (3) between tumbling steel

balls in a cylinder, or (4) in various types of hammer or impact grinding mills. (Alternative concepts have been proposed, such as using high-pressure air jets to cause particle collisions and attrition, but these concepts have much higher energy costs than conventional pulverizer designs.) The principal types of coal pulverizers may be classified under the heading of high-, medium-, and low-speed.

A typical medium-speed ball-and-race type pulverizer is shown in Figure 2. This design has one stationary top ring, one rotating bottom ring, and one set of balls that serve as grinding elements. The pressure required for efficient grinding is obtained from externally adjusting the springs. Raw coal is continuously fed to the grinding zone, where it mixes with partially pulverized coal that forms the circulating load. The coal is carried by the preheated primary air and circulated through the grinding elements. The internal circulation of coal promotes rapid drying and keeps the



(Source: Babcock and Wilcox 1972, p 9-6.)

Figure 2. Medium-speed ball-race pulverizer.

grinding elements constantly loaded. As the coal becomes fine enough to be picked up by the air, it is carried to the classifier where the oversized coal is separated and returned to the grinding zone. The classifier is a multiple-inlet cyclone with adjustable inlet vanes to permit varying inlet velocity as required to obtain the desired fineness of the pulverized coal. Ball-and-race pulverizers are usually designed to operate under positive pressure.

There are two types of roll-and-race pulverizers: (1) standard and (2) the bowl mill. In the standard roll-and-race pulverizer, the grinding elements of one or more rolls rotate in a horizontally positioned stationary race. Roll-and-race pulverizers have been extensively used for bin systems, but are not considered suitable for direct-firing conditions because they must be shut down to lubricate the internal roll journals.

A typical medium-speed roller-bowl mill is shown in Figure 3. The major components are a rotating bowl equipped with a replaceable grinding ring, two or more stationary tapered rolls, an automatic feeder, a classifier, and a main drive. The rolls in the bowl mill are held in position by mechanical springs, and the centrifugal force is used only to feed the coal between the race and the rolls. The bowl mill is suitable for continuous operation because the roller journals can be lubricated and the rolls adjusted without shutting down the unit. The bowl mill is usually designed to operate under suction, and the pulverizer fan is placed on the outlet side of the classifier. Bowl mills are used extensively in direct-firing systems, for steam boilers, and cement kilns.

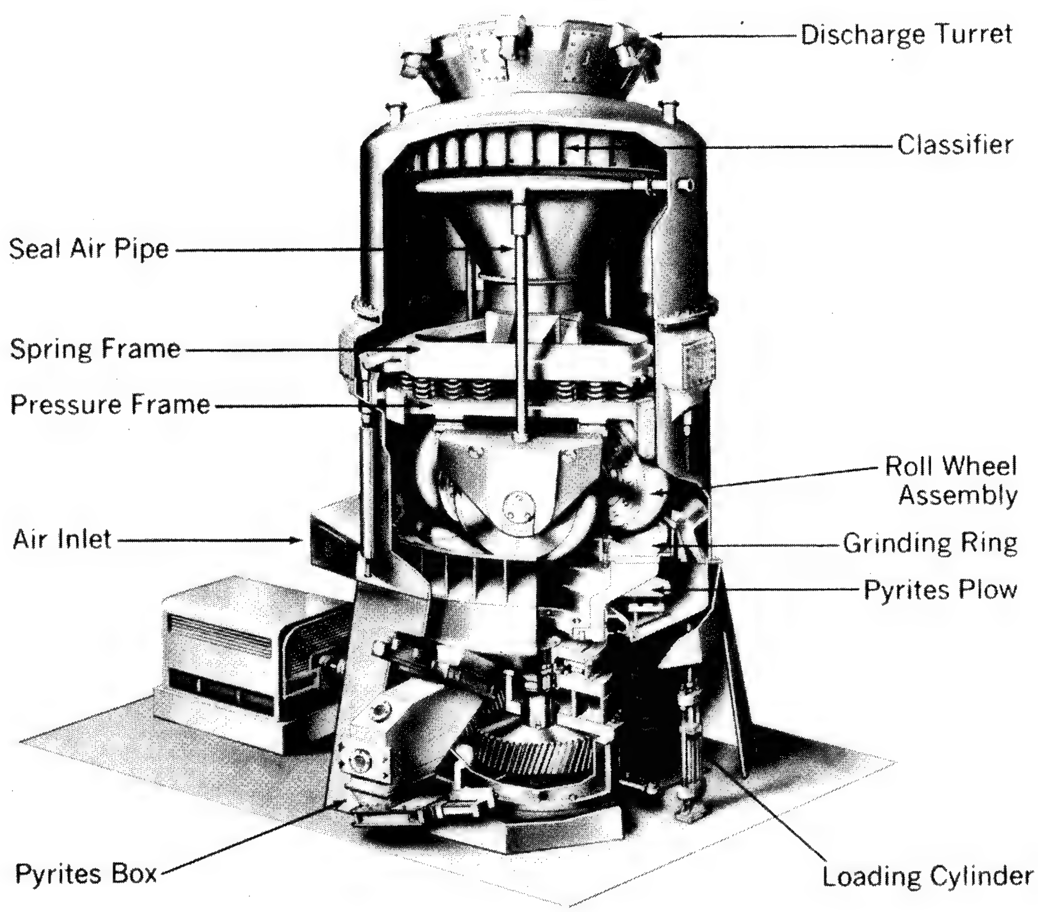
In a high-speed impact pulverizer, as shown in Figure 4, the grinding elements consist of hammer-like beaters revolving in a chamber lined with wear-resistant plates. These machines are used in Europe with subbituminous and brown coals of high moisture content. The product is more comparable to the crushed coal used for a cyclone furnace than to pulverized coal as used in the United States.

A slow-speed tube mill is shown in Figure 5. A charge of mixed-sized forged steel balls in a horizontal grinding cylinder is activated by gravity as the cylinder is rotated. The coal is pulverized by attrition and impact as the ball charge ascends and falls within the coal. The main features of tube mills are their dependability and low maintenance costs as a result of their simple and sturdy construction. However, the absence of load circulation within the mill results in significant capacity reduction, especially when handling wet coals. The tube mill also requires higher operating power because of its size and weight. Therefore, most tube mills have been replaced by the more efficient pulverizers described earlier.

The fine consistency of PC is determined by coal grindability and the spring/centrifugal force on the grinding surface devices. The grindability of a coal is expressed as an

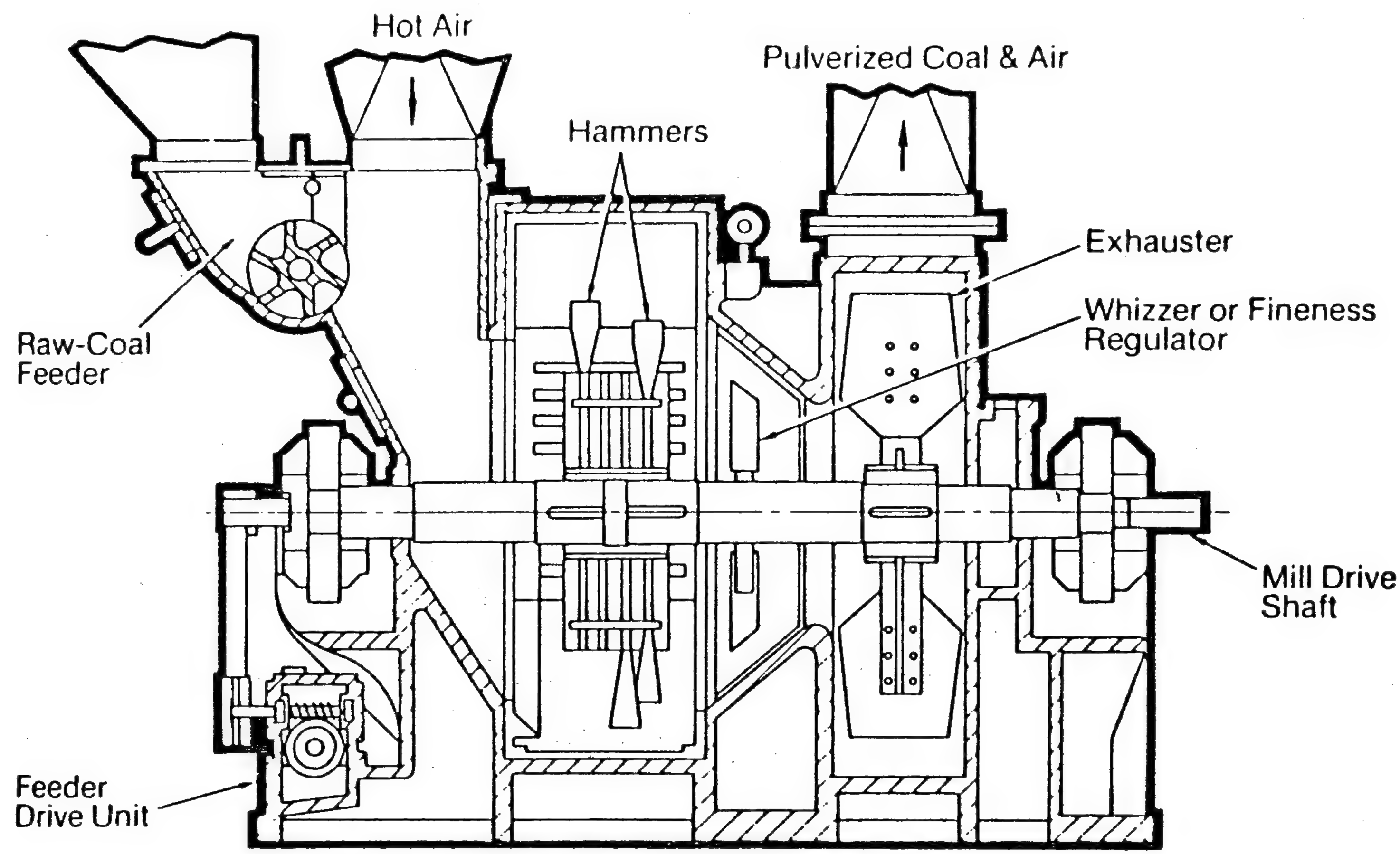
index showing the relative hardness of that coal compared to a standard coal chosen as 100 grindable. The pulverized-coal size is also determined by the oversize particles rejected by the classifier. In a typical installation, coal fineness ranges 70 to 80 percent through a 200 mesh.

The turndown range of a pulverizer is typically 2:1 to 3:1, depending on the type. Excessive coal moisture or hardness can reduce a pulverizer's capacity to as low as 50 percent of its rated capacity. Because of these limitations, a PC-fired boiler usually requires more than one pulverizer. Because pulverizers are subject to considerable wear and maintenance requirements, a backup pulverizer is typically provided for the system.



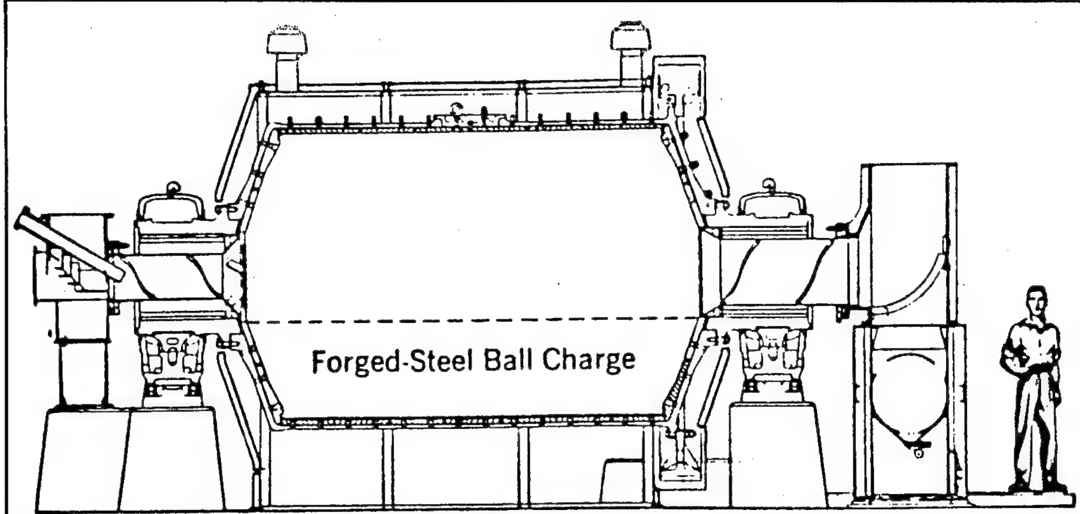
(Source: Babcock and Wilcox 1972, p 9-7.)

Figure 3. Medium-speed roll-race pulverizer.



(Source: ABB Combustion Engineering, Inc. 1991.)

Figure 4. High-speed impact pulverizer.



(Source: Babcock and Wilcox, Inc. 1972, p 9-8.)

Figure 5. Low-speed tube mill pulverizer.

The most commonly used PC burners are the circular and cell types. Figure 6 shows a circular burner designed for firing pulverized coal only. Figure 7 shows a cell burner equipped to fire pulverized coal, oil, and gas. Pulverized coal requires more excess air for satisfactory combustion than either oil or natural gas because of the inherent uneven distribution of coal to individual burner pipes and fuel discharge nozzles. The minimum acceptable quantity of unburned coal is usually obtained with 15 percent excess air, as measured at the furnace outlet at high loads.

In the design of the burner and furnace of a PC-fired unit, consideration must be given to the burner arrangement and furnace configuration to minimize slagging or fouling from coal ash. The burners may be installed (1) horizontally for front-, rear-, or side-wall firing, (2) vertically for firing through the roof of the furnace, (3) both in front and rear walls for opposed firing, and (4) in the corners of the furnace for tangential firing. The type of burner arrangement used depends primarily on boiler size and coal type.

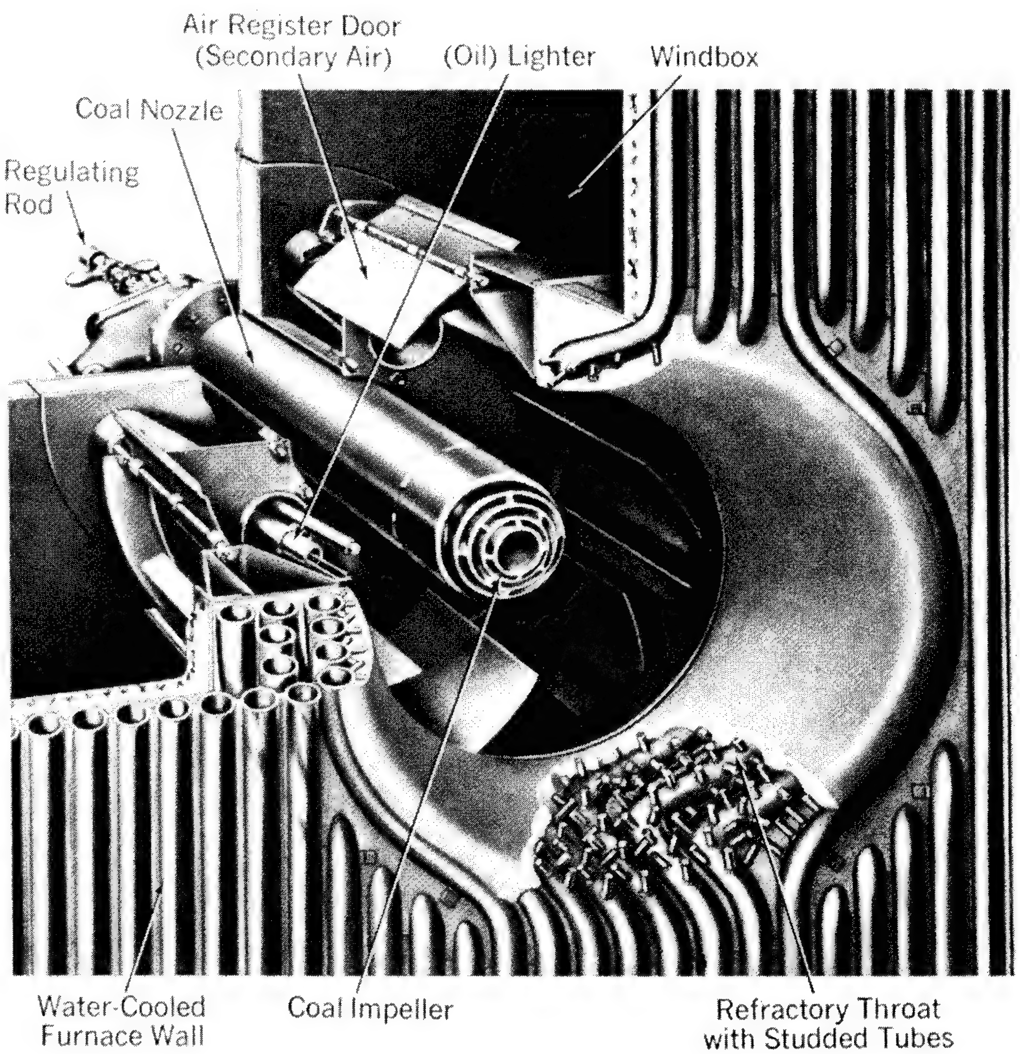
PC-fired boilers can fire a wide range of coals. Although bituminous coals are by far the most common fuel for pulverized coal units, everything from anthracite (very hard) to lignite (very soft) has been fired in utility-size PC units. The problems with these coals is that they are more difficult to grind: very hard coals produce excessive wear, and soft or high-moisture-content coals reduced the delivery capacity of the p-ulverizers. Both extremes of hardness also result in higher energy costs. Consequently, bituminous coal is by far the most commonly used coal in utility operations.

The most important operating considerations in selecting a fuel are (1) ignition and flame stability, and (2) effect of ash properties, including ash handling and deposits. To assure stability of ignition, the temperature of the coal-air mixture leaving the

pulverizer must be at least 180 °F for coals with 20 percent volatile matter. The required mixture temperature decreases as the volatile matter content of the coal feed increases.

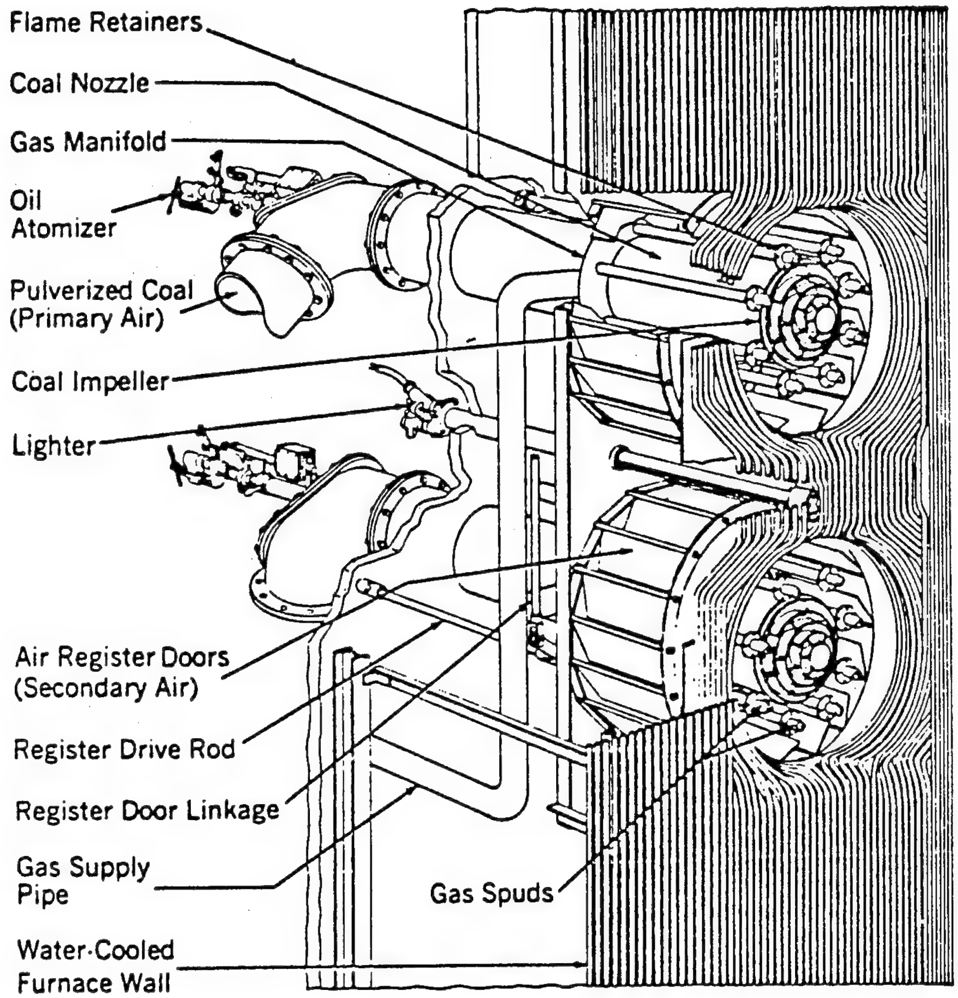
Ash properties affect the coal's ash handling and deposit characteristics. Ash deposits and slagging are more of a problem in PC firing than in stoker firing. Most modern PC boilers have dry-bottom furnaces, that is, the ash is removed as a dry solid. For dry-bottom furnaces, it is necessary that the coal's ash-fusion temperature be sufficiently high to prevent the ash becoming a running slag.

The second ash-related consideration is the accumulation of deposits on the furnace walls or convection surfaces. Ash deposits can reduce the rates of heat transfer, plug



(Source: Babcock and Wilcox, Inc. 1972, p 9-11.)

Figure 6. Circular burner for pulverized coal.



(Source: Babcock and Wilcox, Inc. 1972, p 9-11.)

Figure 7. Cell burner for PC, oil, and gas firing.

gas passages, and induce corrosion. Deposit and corrosion problems are generally more severe in PC units than in other types of furnaces. PC-fired furnaces generally include wall blowers and soot blowers to remove deposits via a stream of compressed air or steam. However, the presence of certain minerals or elements in the coal ash can cause the deposits to sinter or fuse, thus reducing the effectiveness of the blowers. Iron and alkalis (sodium and potassium) are especially important ash constituents when considering furnace wall and convection tube deposits.

Several indicators exist for evaluating the tendency of coal ash to form molten deposits and evaluating the thickness of accumulated deposit layers that become self-limiting due to the presence of running slag. These indicators include (1) temperature of critical viscosity (TCV), (2) ash viscosity, (3) ash softening temperatures, and (4) slagging factors. Coals with low TCV and ash-softening temperatures tend to form

molten deposits at lower temperatures than coal with high TCV and ash-softening temperatures.

Empirical indices have been developed to predict slagging and fouling potentials for various coals, based on the ash analysis and relative distributions of constituents. Some of these slagging factors have been verified by operating data and used as a basis for furnace design. Table 1 presents some ash characteristics of typical U.S. coals, showing various softening temperatures and some slagging factors.

The minimum size of PC boilers has varied, mostly as related to operation and maintenance (O&M) costs of boilers firing competing fuels. PC boilers are more expensive to construct and maintain than oil- and gas-fired boilers. Theoretically it would be possible to use PC in boilers with a capacity less than 20,000 pounds of steam per hour. However, the lack of demand for small units limits the availability of these units and their associated components, so the realistic minimum size of PC boilers tends to be about 100,000 lb/hr.

Table 1. Ash characteristics of typical U.S. coals.

	Rank							
	Low-Volatile Bituminous		High Volatile Bituminous			Sub-bituminuous	Lignite	Lignite
Seam	Pocahontas No. 3	No. 9	Pittsburgh No. 6					
Location	West Virginia	Ohio	W. Virginia	Illinois	Utah	Wyoming	Texas	No. Dakota
Ash, % (dry basis)	12.3	14.10	10.87	17.36	6.6	6.6	12.8	11.2
Sulfur, $ (dry basis)	0.7	3.30	3.53	4.17	0.5	1.0	1.1	0.8
Analysis of Ash, wt %								
SiO_2	60.0	47.27	37.64	47.52	48.0	24.0	41.8	28.4
$A1_2O_3$	30.0	22.96	20.11	17.87	11.5	20.0	13.6	11.9
TiO	1.6	1.00	0.81	0.78	0.6	0.7	1.5	0.4
Fe_2O_3	4.0	22.81	29.28	20.13	7.0	11.0	6.6	14.0
CaO	0.6	1.30	4.25	5.75	25.0	26.0	17.6	18.0
MgO	0.6	0.85	1.25	1.02	4.0	4.0	2.5	5.0
Na_2O	0.5	0.28	0.80	0.36	1.2	0.2	0.6	3.6
K_2O	1.5	1.97	1.60	1.77	0.2	0.5	0.1	0.7
Total	98.8	98.44	95.74	95.20	97.5	86.4	84.3	81.1
Ash Fusibility								
Initial Deformation								
Temperature, °F (IT)								
Reducing	2900+	2030	2030	2000	2060	1990	1975	2170
Oxidizing	2900+	2420	2265	2300	2120	2190	2070	2170
Softening Temperature, °F								
Reducing		2450	2175	2160		2180	2130	2200
Oxidizing		2605	2385	2430		2220	2190	2210
Hemispherical Temperature °F (HT)								
Reducing		2480	2285	2180	2140	2250	2150	2230
Oxidizing		2620	2450	2450	2220	2240	2210	2230

Rank								
	Low-Volatile Bituminous		High Volatile Bituminous			Sub-bituminuous	Lignite	Lignite
Fluid Temperature, °F								
Reducing		2620	2370	2320	2250	2290	2240	2310
Oxidizing		2670	2540	2610	2460	2300	2290	2370
Type of Ash	Eastern	Eastern	Eastern	Eastern	Lignite	Lignite	Lignite	Lignite
Base/Acid Ratio (B/A) $Fe_2O_3 + CaO = MgO + Na_2O + K_2O/SiO2 + A1_2O_3 + TiO_2$	0.070	0.382	0.635	0.439	0.622	0.933	0.482	1.04
Silica Ratio $SiO_2 \times 100/sIO_2$ $Fe_2O_3 + CaO + MgO$	92	65	52	64	57	37	61	43
Dolomite, % $(CaO + MgO)$ $100Fe_2O_3 + CaO + MgO + Na_2O + K_2O$	17	8	17	23	78	72	73	56
Slagging Potential for Eastern Coal (B/A x % S)	Low: 0.06	Medium: 1.26	High: 2.24	Medium: 1.83	Low: 0.31	Medium: 0.93	Low: 0.53	Medium: 0.83
Slagging Potential for Lignite Ash Max HT + 4 IT/5	---	High: 2148	High: 2114	Severe: 2090	Severe: 2092	Severe: 2042	Severe: 2022	High: 2182
Fouling Potential for Eastern Coals (B/A x % Na_2O)	Low: 0.04	Low: 0.11	Medium: 0.51	Low: 0.16	High: 0.75	Low: 0.19	Medium: 0.29	Severe: 3.74
Fouling Potential for Lignite Ash (% Na_2O)	Low-Medium: 0.5	Low-Medium: 0.28	Low-Medium: 0.80	Low-Medium: 0.36	Low-Medium: 1.2	Low-Medium: 0.2	Low-Medium: 0.6	High: 3.6

3 Screening Model

A computer-based screening model has been developed to aid Army planners in the preliminary evaluation of potential sites for coal-fired central heat plants. The screening model for pulverized-coal boilers consists of four sections:

1. New Heating Plant Screening Model
2. Cogeneration Screening Model
3. Third Party Cogeneration Model
4. Consolidation Screening Model.

The screening models allow the user to specify the facility's characteristics and energy needs. Based on the information supplied and internal database information, the program lists the relevant plant parameters. In addition to calculated outputs such as peak boiler-house loads, a subjective weighted analysis output is provided. The output provides information for the comparison of potential sites with available technologies and other locations.

New Heating Plant Screening Model

The New Heating Plant Screening Model can be used to determine the feasibility of constructing a new PC-fired heating plant at an installation (150 psig saturated steam or equivalent hot water). The software prompts the user to supply information describing the user's requirements and resources available to the new heating plant. Based on the information supplied and internal program information, the program output gives conceptual area requirements, steam heating load predictions, plant performance estimates, fuel storage area requirements, location site information, boiler coal specifications, coal analysis, boiler sizes, allowed emissions, calculated emissions, and water requirements. In addition, a weighted analysis is provided for the subjective factors considered when deciding to build a new heating plant.

The screening model has three basic sections: (1) the interactive query section, (2) internal databases, and (3) engineering calculations. The computer prompts the user for required information about the installation. The program then determines the feasibility of a new facility using the supplied information, databases and calculations.

The New Plant Screening Model is divided into a number of sections, each focusing on a specific aspect of building a new heating plant. For each of these sections, user inputs are required to evaluate relevant criteria. The following discussion reviews each section, including the inputs required as well as the computer logic and actions. The algorithms, where relevant, are also provided.

Plant Site Information

This section of the model requires the user to enter the state in which the new heating plant will be located. Upon entering the state, the military bases in the specified state are automatically listed on the screen for the user to select from. If the state is divided into a number of regions for emission regulations, the user will be prompted to identify the appropriate region.

Heating Plant Monthly Loads

The heating plant load demand calculation requires the following information: the type of boiler plant to be built (steam or HTHW), the average hourly steam demand for each month in lb/hr (hot water in MBtu/hr), and the process steam demand for each month in lb/hr (only for steam). The user is requested to input these values and confirm that they are correct before continuing.

Heating Plant Maximum Continuous Rating Calculations

The steam load prediction formulas calculate the plant maximum continuous rating (PMCR) steam flow in lb/hr. If the PMCR is outside of the model's plant size limit—60,000–600,000 lb/hr (approximately 60 million–600 million Btu/hr)—the program will alert the user to this fact. The following algorithms are used for a specific location with known long-term average monthly degree days, long-term mean monthly ambient air temperatures, and monthly average steam flows in lb/hr.

Average Monthly Steam Flow (lb/hr) = [PMCR] [A * B * C + A * C * D + 0.125] [LF]

where: A = Ta/Tm

B = DDM/DDCM	DDM>1.0 & DDCM>1.0
C = (T -Ta) / (Td-To)	T-Ta> +1.0
D = [0.5][(PDDM + DDPM) - DDCM]	
[PMCR] A B C > + 500	
[PMCR] A C D > + 500	

PMCR	=	Plant Maximum Continuous Rating, the total plant maximum continuously required steam flow in lb/hr.
DDM	=	Degree Days of the specific Month being predicted. This is a long-term average value. Value should be an average of at least the previous 10 years.
DDCM	=	Degree Days of the Coldest Month of the year. This is the month with the most degree days. The value is a long-term average. The value should be an average of at least the previous 10 years.
PDDM	=	Predicted Degree Days of the specific month being predicted. This can be equal to the DDM value, or some other value depending on the user's prediction of the month's degree days. (Default should be the DDM value).
DDPM	=	Degree Days of the Previous Month being predicted. This is equal to the previous month's degree days. This value can be either an actual value or a long-term value depending on the user. (Default should be the 10-year average degree days value of the month previous to the specific month.)
T	=	Average indoor building temperature (°F) for the month. Default should be 70 °F.
Ta	=	Average ambient outdoor temperature (°F) of the specific month.
Td	=	Indoor design temperature. Default should be 70 °F.
Tm	=	Outdoor yearly mean temperature (°F). This value is a long-term (minimum of 10 years) average of the mean temperature.
To	=	Outdoor winter design temperature (°F). This value should be based on the once-in-13 or once-in-20 years frequency of recurrence temperature.
LF	=	Load factor for each month determined from actual long-term data for a specific installation. For a new plant or a plant without actual data, the following values are suggested:

– Months of December, March, and April: LF = 0.836.

- First month of the heating season: LF = 1.333. The first month in the north is September and in the south is October.
- Months of June and July: LF = 1.08
- All other months: LF = 1.0

Distribution System Minimum Monthly Steam Flow (lb/hr) = (PMCR) (0.09)

Plant Minimum Total Steam Flow (lb/hr) = (PMCR) (0.08)

Plant Average Low Monthly Steam Flow (lb/hr) = (Average Monthly Steam Flow) - (LLF) (PMCR) (LDDCM) / (BDD)

where: LLF = Low Load Factor for the specific month in question and are:

Jan.	= 0.16	Jul.	= 0.02
Feb.	= 0.16	Aug.	= 0.02
Mar.	= 0.14	Sept.	= 0.06
Apr.	= 0.12	Oct.	= 0.085
May	= 0.08	Nov.	= 0.11
June	= 0.035	Dec.	= 0.14

(LLF) (LDDCM) / (BDD) > 0.02

LDDCM = The specific Location Degree Days of the Coldest Month in question.
BDD = Base Degree Days = 1250

Plant Maximum Monthly Steam Flow (lb/hr) = (Average Monthly Steam Flow) + (PLF) (PMCR) (LDDCM) / (BDD)

where: (PLF) (LDDCM) / (BDD) = 0.07

PLF = Peak Load Factor for the specific month in question:

Jan.	= 0.40	Jul.	= 0.07
Feb.	= 0.40	Aug.	= 0.07
Mar.	= 0.40	Sept.	= 0.22
Apr.	= 0.38	Oct.	= 0.25
May	= 0.25	Nov.	= 0.33
June	= 0.15	Dec.	= 0.40

(Note that predictions are only for heating facilities without any type of cogeneration or air conditioning loads in the summer.)

Boiler Technology

In this section of the screening model the type of boiler plant to be analyzed is selected. The user specifies that the case being considered by the screening model is a pulverized coal-fired boiler.

Conceptual Boiler Sizing

PC firing is generally used where the required boiler steam capacity is in excess of 100,000 lb/hr. This is due to limitation of size, ability to respond to changes in load, thermal efficiency related to amount of excess air requirements and carbon loss, and ability to burn coal in combination with gas or oil. Also, manpower requirements for PC-fired boiler operation are lower than stoker-fired units.

This section allows the user to select a conceptual plant with three, four, or five boilers. Along with the number of boilers, the equations require the plant design PMCR to be entered as input, where PMCR is derived from the plant monthly loads. The user's selection is then used to determine the correct size for each of the plant's boilers, in lb/hr outlet flow. If the boiler sizes are outside the feasible size range of 100,000–275,000 lb/hr, the program will alert the user to the problem and allow the user to quit, change the number of boilers or change the plant demand. The following describes the boiler sizing methods and equations:

- *Three-Boiler Plant*
  One Small Boiler sized by: Capacity = (0.30) (PMCR)
  Two Large Boilers; each sized by: Capacity = (0.45) (PMCR)

- *Four-Boiler Plant*
  One Small Boiler sized by: Capacity = (0.30) (PMCR)
  Three Large Boilers sized by: Capacity = = (0.35) (PMCR)

- *Five-Boiler Plant*
  All boilers sized by: Capacity = (0.25) (PMCR)

The three-boiler sizing method provides for the plant to generate 75 percent of the PMCR with one large boiler out of service. The four-boiler plant will be able to generate 100 percent of the PMCR with one large boiler out of service. The five-boiler

plant will also be able to generate 100 percent of the PMCR with one boiler out of service.

The four-boiler plant is the default method. With this sizing configuration, the plant will be able to meet the minimum heating loads of summer, the possible over-demands of winter, provide for a small future capacity increase, and includes a redundant boiler. The redundant boiler is used to cover forced boiler outages. The plant will be able to utilizee the four boilers in a pattern typical of coal-fired boiler heating facilities. In the summer (minimum heating season) the plant will use or have on-line the small boiler. During the fall season, when steam demand will be increasing, the plant will bring on-line a large boiler with the small boiler. Sometime during the fall season, the small boiler will be taken off-line and replaced with another large boiler. The timing will depend on the specific seasonal conditions and steam system requirements. In late fall or early winter the plant will bring on-line the third large boiler, thus enabling the plant to meet the highest requirements at the most demanding time of the year. Sometime at the end of the winter season or the beginning of the spring season, the plant will take off-line one large boiler and bring on-line the small boiler again. During the spring season, the plant will take off-line the large boilers (one at a time) until only the small boiler is on-line for the summer load. The cycle will then begin again.

The following reasons motivate the use of the three large boilers during the winter season: at this time of the year the plant will be required to utilize frozen or wet coal, and the ambient air and water temperatures will be at the lowest values. Also, the plant will be required to supply the highest in-plant steam/heat usage, as well as supplying the largest system load.

The default sizing formula also includes an understanding of scheduled boiler maintenance. Each boiler will be off-line for scheduled maintenance approximately 1 month per year. This will probably be one continuous month or two 2-week periods during the year. Also, approximately every 5 years, each boiler will be scheduled for a major overhaul. Each major overhaul will be performed over a time period of approximately 30 to 60 continuous days. Experience shows the plant will schedule yearly boiler outages, depending on the season. The large boilers will have scheduled maintenance performed sometime during the spring, summer, and fall seasons; one boiler is scheduled for maintenance at a time. The small boiler will have scheduled maintenance performed sometime during late fall, early winter, or late winter. (This will keep the small boiler available during the coldest part of the winter as backup for the largest boilers, which is advisable because forced or unscheduled boiler outages usually occur when the boilers are operated near-maximum conditions.)

The model's default boiler and plant sizing optimizes the design of the facility's major components to ensure availability and reliability through all significant factors likely to influence facility operation.

Coal Specification

Primary considerations for selection of coals for PC boilers are the grindability index, moisture content, volatile matter, and ash. Generally, coal with ash content not exceeding 20 percent and moisture content not exceeding 15 percent is most suitable for PC firing. Table 2 shows the coal specifications for pulverized coal boilers.

The following sections of the model address coal specification as it relates to the unique requirements of PC combustion. The effects of coal characteristics are particularly important for proper sizing of pulverized coal equipment.

Pulverizer Sizing

To determine the pulverizer capacity required for a given boiler, it is necessary to know boiler output, and efficiency, fuel heating value, Hardgrove grindability index, and coal moisture content. Pulverizers are sized to deliver the required mass flow rate at the minimum fineness necessary for complete combustion. For bituminous coals, a fineness of 70 percent through a 200-mesh screen is normally required, but for western subbituminous coals having a somewhat higher volatile content, a fineness of 65 percent through a 200-mesh screen is adequate. Lowering the fineness required increases pulverizer capacity, while lowering the grindability or increasing fineness decreases pulverizer capacity. Increased moisture also lowers pulverizer capacity. Figure 8 is a typical curve for determining pulverizer capacity.

Table 2. Coal specification recommendations for PC-fired boilers.

	Subbituminous	Bituminous
Proximate Analysis		
Moisture (M)	10-31%	0-20%
Volatile Matter (VM)	20-40%	30-40%
Fixed Carbon (FC)	30-50%	40-50%
Ash	5-20%	5-20%
Heating Value. Btu/lb	8,300-11,500	10,500-14,000
Hemispherical Ash Softening Temperature (H = 1/2 W Reducing) 2,150 °F		
Free Swelling Index 7 Maximum		
Size Top Size = 1-1/4 inch		

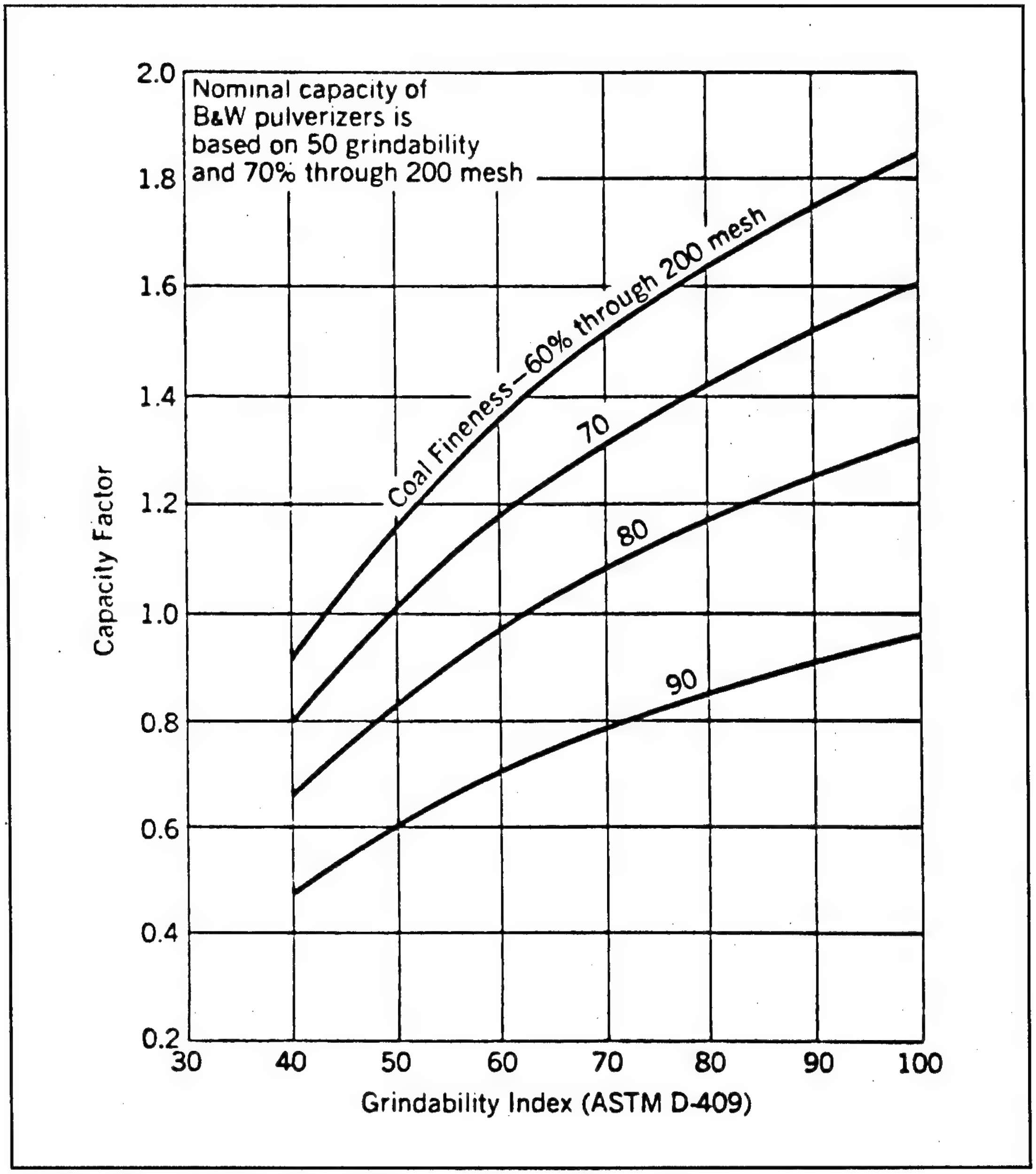


Figure 8. Effect of grindability and fineness on pulverizer capacity.

The pulverizer capacity should be sufficient to handle the worst-case condition of low heating value and low-grindability coal. One spare pulverizer should be provided so a full load can be maintained if a pulverizer is out of service for maintenance. For a unit designed for a specific fuel, the size and number of pulverizers would be optimized to provide full-load capacity and low-load turndown capability. Pulverizers normally have a minimum capability of 25–50 percent. Therefore, a unit with fewer large pulverizers will have a higher minimum load than a unit with more small pulverizers. The size of pulverizers for a specific installation is only determined after the amount of coal to be used is specified.

Boiler Efficiency

Boiler efficiency and fuel heating value are used to determine the fuel mass flow rate for which sizing of the coal-handling equipment, silo volumes, and coal yard storage area must be based.

The primary factors controlling boiler efficiency are excess air required to burn the fuel, flue gas temperature leaving the air heater, and hydrogen and moisture content of the fuel. The minimum excess air required depends on how effectively the combustion air is distributed and mixed with the fuel. Typically, 15–20 percent excess air is required at full load, with higher amounts at partial load. The volatile matter content of the coal relates to the combustibility of the coal, and is a factor in burner design and unburned carbon loss. The hydrogen and moisture content of the coal as determined from the ultimate analysis are used to calculate the efficiency loss due to water vapor in the flue gas. A typical boiler efficiency when burning western subbituminous coal is 85 percent.

Coal Handling

Coal characteristics that influence the coal-handling system consist of the higher heating value (HHV) and moisture. For a given unit burn rate, coals with low gross calorific value would require a higher-capacity coal-handling system to meet the fuel requirements of the plant. Rather than increase conveyor belt speeds to increase capacity, wider belt widths are recommended. It is advisable to operate belt conveyors at a lower speed to reduce dusting and spillage of the coal in transit.

Surface moisture must also be considered in the design and layout of the conveyor system. In cold climates, rail-delivered coal may require a car-thawing facility at the unloading station to break the bond between the rail car and the coal within the car, or to thaw the hopper doors of bottom-dump cars. Frozen-coal crushers located at the unloading facility hopper outlets should also be considered to break any large frozen lump discharged from the coal car.

Coal delivered by barges and rail during rainy periods may contain so much moisture that it cannot be conveyed on the belts without spillage and runback. In such a case, provisions should be made for dewatering. The angle of incline of the take-away conveyor at the loading area should also be reduced to permit the wet material to stabilize on the conveyor.

Flue Gas Desulfurization System

Sulfur content of the coal to be burned is a major factor in determining the type of flue gas desulfurization (FGD) system that will be used on a project. The 1978 New Source Performance Standards (NSPS, 40 CFR 60) require a maximum SO_2 emission rate of 1.2 lb/10^6 Btu input and a minimum removal of 70 percent. For new plants burning low-sulfur coal, 70 percent of the SO_2 must be removed and the SO_2 emissions must be reduced to 0.6 lb/10^6 Btu. New plants burning high-sulfur coal are typically required to meet 1.2 lb/10^6 Btu and 90 percent SO_2 removal.

The selection of an FGD system is coal-and site-specific. A number of technologies are available for consideration, including wet lime and lime spray drying, and regenerative processes.

Ash Handling

Coal characteristics that influence the ash-handling system consist of the HHV, moisture, and ash.

Since a change in the HHV changes the mass firing rate, the ash quantities produced also change. HHV variations result in inversely proportional changes in the ash production.

Moisture can affect the collection of fly ash from precipitator hoppers by the reaction of the moisture with the ash minerals to form hydroscopic salts. These hydroscopic salts result in a sticky mass that will cause difficulty in removal well above the dew-point temperatures of the flue gases.

For a coal ash with 10 percent or more CaO, a dry fly ash collection and handling system is recommended. If fly ash of this type is mixed with water, it can solidify much like concrete. Dry fly ash handling is also recommended to provide ash for blending with wet FGD waste, for sale of ash, and to minimize wastewater discharge. The bottom ash system is not affected by the CaO content of the ash.

Precipitator or Baghouse

The choice of equipment for controlling particulate emissions depends on the characteristics of the fly ash and the type of FGD system selected.

Fly ash from high-sulfur coal can successfully be collected in either a baghouse or cold-side electrostatic precipitator. The lower particulate emission limits of the 1978 NSPS (0.03 lb/10^6 Btu) have made baghouses more competitive, especially for low-sulfur coal.

The resistivity of fly ash from low-sulfur subbituminous coal varies inversely with sodium oxide content and directly with the lime content of the ash. Low-sulfur subbituminous coal that has less than 2 percent Na_2O may require a baghouse or a cold-side precipitator. A baghouse may also be used downstream of a dry FGD system. Hot-side precipitators on low-sulfur western coals have experienced many performance and structural problems, and are not recommended.

Fans

Coal characteristics that influence fan performance consist of moisture, higher heating value, sulfur, ash, and ash composition. The effects of coal quality on fan performance are discussed below.

Forced-Draft Fans and Moisture. Forced-draft (FD) fans are affected by moisture in coal indirectly. As coal moisture increases, the required firing rate increases due to the decrease in boiler efficiency caused by increased vaporization losses. The total air supplied by the FD and primary air fans for combustion increases in direct proportion to the increase in firing rate. However, as the moisture content of the coal increases, the amount and required temperature of the primary air increases, resulting in less than a 1:1 relationship with the firing rate for the quantity of air required from the FD fans. On some systems, the FD fans must provide the total air required.

Induced-Draft Fans and Moisture. Increasing coal moisture causes increased combustion products that the induced-draft (ID) fan must handle (due to increased fuel input requirements). A 10 percent increase in moisture will increase the gas mass quantity to the ID fans by roughly 1 percent.

Increased moisture in the coal results in increased water vapor present in the flue gas stream. Sulfur trioxide in the gas—formed by oxidation of sulfur dioxide—and water have a tremendous affinity for each other, forming sulfuric acid when gas temperatures are lowered to the dew point. The sulfuric acid dew point is the temperature at which liquid sulfuric acid begins to condense in the flue gas. Increased moisture in the gas stream tends to elevate the acid dew point (roughly 12 °F for a 10 percent moisture-by-volume increase). Thus, increased coal moisture influences the condensation of sulfuric acid due to the resulting increase in water vapor in the flue gas.

Primary Air Fans and Moisture. The primary air flow at maximum load is directly related to the coal-firing rate, and as coal moisture increases, both the required amount and temperature of the primary air will increase. The amount of primary air required increases due to the moisture, which requires an increased coal-firing rate to maintain the same heat input to the boiler. The primary air/coal moisture temperature to the burners is usually maintained at 150–180 °F. As coal moisture increases, primary air quantities and temperature must increase to dry the coal. Considerations must be given to the primary air velocity limitations at the burner nozzle, the air velocity at the pulverizer throat, and the proper air-to-fuel ratio in order to maintain stable ignition. Also, pulverizers require a relatively high minimum air flow to properly convey the coal through the pulverizer separators and through the coal piping to the burners.

Unique pulverizer and burner coordination for a specific application should be plotted to indicate the maximum capability, the operating range, and the permissible limits of both the pulverizers and burners. The pulverizer and burner coordination curves relate the pulverizer capacity to primary air requirements for stable load operation.

Gas Recirculating Fans and Moisture. The possibility of increased fan corrosion should be considered due to the potential of increased sulfuric acid condensation during startup and shutdown, when gas temperatures are below the sulfuric acid dew point. The changing air requirements and combustion products resulting from changes in the moisture of the coal will affect the gas recirculation fan due to changes in furnace heat absorption.

Higher Heating Value. Changes in HHV result in inversely proportional changes in the amount of coal fired. A 1 percent decrease in HHV corresponds to a 1 percent increase in FD primary air and ID fan flows.

Sulfur. The main concern related to an increasing sulfur content is the increased potential for corrosion of the gas-handling fans by the formation and condensation of sulfuric acid when sulfur trioxide and moisture react. Most of the sulfur in the flue gas appears as sulfur dioxide, with typical sulfur trioxide levels ranging from 1 percent to 3 percent of the sulfur dioxide.

Database information relating increased sulfur content to increased corrosion is limited and often contradictory. The oxidation of sulfur to SO_2 and SO_3, the chemical reaction with the moisture in the air/gas stream, and the sulfuric acid dew point vary greatly. Definitive relationships are not established. Corrosion rates of gas-handling fans are also a function of fan materials of construction.

Ash. Increased ash loading increases fan wear for the ID and gas recirculation fans. Fan wear as related to ash loading is a function of fan type and construction materials. Fan blade wear is a function of ash particle speed relative to blade tip speed. The empirical formula for blade life expectancy shows blade life to be inversely proportional to the quantity of fly ash, silica content, and weight of fly ash exceeding 25 microns in mean particle size. Axial fans, due to their higher velocities at blade tip, can be expected to have higher wear rates for the same blade material than the centrifugal fans, with their lower speeds at blade tip.

Ash Composition. As with ash loading, ash composition affects the wear of the gas-handling fans. Abrasive components of the ash, such as silica, cause fan wear. Definitive guidelines relating ash composition to fan wear are not established.

Fuel Search

The model's fuel search section requires the user to enter the radius in miles from the base for the fuel search. The program searches the COALFIELD database (Kinast and Blazek, January 1989) for coal deposits within the specified radius, and compares the required coal specifications for the chosen boiler type to each coal deposit to determine which coal can be used.

The coal deposits are sorted according to coal type (lignite, bituminous, anthracite) and arranged by the heating value. For the chosen coal deposit, the coal type, heating value and proximate analysis are displayed. At this point, the user has the option of choosing the fuel for analysis, changing the radius of the fuel search, or further eliminating coal mines by specifying a maximum sulfur limit.

Water Requirements

When considering building a new boiler plant, the amount of water required must be estimated. Estimates for boiler leakage, condensate return, blowdown as percentages of PMCR must be entered. The amount of water required is estimated by the following algorithm:

Water (gpm*) = (PMCR) [1 + % Blowdown/100 - % Condensate Return-/100]/500

where: PMCR is an input from the Plant Performance Estimate Program.

* gpm: gallons per minute.

% Condensate Return is a user input value with a range of 0-100 percent and default of 50 percent.

% Blowdown is a user input value with a range of 0-10 percent and default of 5 percent.

Plant/Boiler Performance Estimates

This section of the model calculates the heat and mass balance for total boiler plant when operating at the plant maximum continuous rating. The assumption for this calculation is that the individual boilers are essentially the same and will operate with the same efficiency regardless of size difference. This presumption is valid for the conceptual design stage and with the boiler-sizing methods in this study.

The program begins with the key boiler data inputs. The boiler sections calculate the American Society of Mechanical Engineers (ASME) boiler efficiency, air requirements and flow, products of combustion and flow, and flue gas specific heats. Table 3 defines the program inputs. Table 4 shows the input ranges and default values.

Plant Area Requirements

To determine whether sufficient area is available to build a new boiler plant, the program calculates plant area, building area, plant height, and stack height using the following formulas:

Three-Boiler Plant Acres	= [(0.004) (PMCR/1000)] + 0.80
Four-Boiler Plant Acres	= [(0.005) (PMCR/1000)] + 0.83
Five-Boiler Plant Acres	= [(0.005) (PMCR/1000)] + 1.0
Three-Boiler Building Size (sq ft)	= (0.04) (PMCR) + 2,760
Four-Boiler Building Size (sq ft)	= (0.05) (PMCR) + 3,600
Five-Boiler Building Size (sq ft)	= (0.06) (PMCR) + 4,300
Plant Height, ft	= (0.11) (PMCR)/1000 + 48
Stack Height, ft	= (2.5) (Plant Height)

The plant area includes boiler building, fuel and lime storage, emission controls, fans, stacks, coal handling, lime handling, ash handling, roads, and parking.

Table 3. Plant/boiler performance input descriptions.

Fuel Ultimate Analysis

The ultimate analysis of the user's selected fuel, expressed as weight percents. The value will be entered from the coal analysis.

Excess Air - %

The percent excess air at which the boiler will be operated.

UBC in Ash - %

The weight percent of carbon in the total boiler ash.

Gas Temperature Leaving Last Heat Trap - °F

The temperature of the flue gas leaving the last heat trap (air heater or economizer) of the boiler envelope.

Ambient Air Temperature - °F

The temperature of air entering the boiler envelope.

Radiation Loss - %

The heat loss due to surface radiation and convection from the boilers. The user can approximate the loss using the American Boiler Manufacturers Association (ABMA) standard radiation loss chart (ABMA 1964).

Manufacturer's Margin - %

The heat loss a manufacturer will use as a "design safety margin."

Unaccounted Heat Loss - %

Unaccounted-for heat losses from unmeasured losses such as pit sensible heat, flue gas dust sensible heat, cooling water, etc.

Main Steam Flow - Lb/Hr

The Plant Maximum Continuous Rating (PMCR) steam flow of the plant. This is the value as determined from the steam load prediction equations.

Blowdown - %

The amount of continuous boiler blowdown expressed as percent of total steam flow.

Air Leak After Last Heat Trap - %

The amount of air leakage into the boiler system and is expressed as a percentage of flue gas flow out of the boiler.

Steam (superheated) Outlet Pressure - psig

The boiler outlet steam pressure.

Steam (superheated) Outlet Temperature - °F

The boiler outlet steam temperature.

Steam (superheated) Enthalpy - Btu/lb

The enthalpy of the steam out of the boilers.

Drum Pressure - psig

The boiler drum operating pressure.

Drum Temperature - °F
The boiler drum operating temperature.

Drum Saturated Liquid Enthalpy - Btu/lb
The saturated liquid boiler drum water enthalpy.

Drum Saturated Vapor Enthalpy - Btu/lb
The saturated vapor boiler drum water enthalpy.

FW Inlet Pressure - psig
The discharge pressure, less piping losses, of the boiler feedwater pumps.

FW Inlet Temperature - °F
Feedwater temperature entering the boiler envelope.

FW Inlet Enthalpy - Btu/lb
Feedwater enthalpy feedwater entering the boiler envelope.

Plant Altitude - ft
The altitude (elevation) of the plant above sea level.

Duct Pressure - Inches Water
The pressure in the flue gas duct inlet of the dry scrubber.

Lime Stoichiometric (Ca/S) Ratio
The feed ratio of calcium to fuel sulfur.

SO_2 Collection Efficiency - %
The percent SO_2 collection efficiency of the dry scrubber.

Boiler Bottom Ash Temperature Leaving - °F.
This is the temperature of the boiler ash leaving the boiler envelope.

Coal Storage Area

The long-term coal storage area includes the long-term coal storage pile, short-term dead storage pile, live or stockout pile, coal reclaim equipment, and a circulation allowance for coal yard vehicles. This total area is to be constructed such that storm water will be collected and directed to the Coal Storage Rain Runoff Pond. The conceptual area allowance calculations are in conformity with Army Technical Manual (TM) 5-848-3, *Ground Storage of Coal* (March 1984).

Table 4. Plant performance estimates ranges and defaults

	Pulverized Coal	Stoker
% Excess Air		
Range	20 - 50	20 - 100
Default	20	40
% UBC in Ash		
Range	5 - 10	5 - 30
Default	5	10
Gas Temperature Leaving Last Heat Trap, °F	280 - 325	325 - 550
Range	300	350
Default		
Ambient Air Temperature, °F		
Range	60 - 90	60 - 90
Default	70	70
Radiation Loss, #		
Range	0.5 - 1.5	0.5 - 1.5
Default	0.7	1
Manufacturers Margin		
Range	0.5 - 1.5	0.25 - 0.75
Default	1	0.5
Unaccountd Heat Loss, #		
Range	0.5 - 1.5	0.5 - 1.5
Default	0.5	0.5
Blowdown, #		
Range	1 - 10	1 - 10
Default	1	5
Air Leak After Last Heat Temperature, #		
Range	5 - 15	0 - 15
Default	10	5

In this subsection of the model, the user has the option of selecting either multiple coal piles or a single pile for the method of long-term storage of coal. The user also has the option of selecting the number of days of long-term and short-term supply storage. Both sets of equations base coal storage on the amount of coal the plant requires while operating at the PMCR.

The user must enter the following:

Number of Days Long-Term Coal Storage
Range: 60 to 100 Days
Default: 90 Days

Long-Term Coal Storage Capacity - Lb = (Days Long-Term Storage) (Coal @ PMCR - Lb/Hr) (24 Hours/Day)

Single Pile Area (Long-Term) - Acres = (Days Long-Term Storage) (Coal @ PMCR - Lb/Hr) (24 Hours/Day) / (70 Lb/CF) (15 ft High)] + 2700 sq ft + (104) [SQRT((Days Long-Term Storage) (Coal @ PMCR - Lb/Hr) (24 Hours/Day) / (70) (15))]) / (43560 sq ft/acre)

Multiple Piles Area (Long-Term) - Acres = ([(Days Long-Term Storage) (Coal @ PMCR - Lb/Hr) (24 Hours/Day) / 350 Lb/sq ft] / (43560 sq ft/acre)

To calculate the area required for the Short-Term Pile Area, the user must input the following:

Number of Days Short-Term Coal Storage
Range: 1 - 3 Days
Default: 1 Day

Short-Term Pile Capacity - Tons = (Days Short-Term Storage) (Coal @ PMCR - Lb/Hr) (24 Hrs/Day)

If the capacity is 200 tons or less, then the pile is 45 ft in diameter and the area required is 0.1 acre. If the capacity is larger than 200 tons, then the program calculates a pile length for the area determination:

Pile Length - ft = (Days Short-Term Storage) (Coal @ PMCR - Lb/Hr) (24 Hrs/Day) / 9 - 22

Pile Area - Acres = (Pile Length - ft + 38) (75 ft) / (43560 sq ft/acre)

Additional area is allocated for circulation around the coal piles.

Circulation Area = 0.5 acre

Additional space is allocated for the reclamation area around the coal piles.

Reclaim Area = 0.5 acre

The total area required for coal storage is the sum of the individual areas.

Total Coal Storage Area - Acres = (Long-Term Pile Area) + (Short-Term Pile Area) + (Circulation Area) + (Reclaim Area)

Coal Storage Rain Runoff Pond

The pond receives storm water runoff from the Long-Term Coal Storage Area. TM 5-848-3 requires the pond to be sized to contain the runoff from a 10-year, 24-hour storm with 2 ft of freeboard. The conceptual sizing method uses an average pond water depth of 4 ft and sizes the pond for 4 in. of rain in 24 hours, with no absorption.

The design of the pond is to conform to the requirements of TM 5-848-3: perforated standpipe with crushed stone, pond sides sloped for cleaning and dredging, the sides and bottom of the pond lined with impervious material to prevent groundwater contamination. The pond includes a water neutralization system to chemically neutralize the pond water. It consists of multiple concrete weir basins installed with the necessary pH detection controls, equipment for adding the appropriate amount of chemicals—usually lime, caustic, or soda ash to neutralize the pond water—agitators to mix the chemicals, and water and pumps to pump the neutralized water to a storm drain or natural water channel.

The basic algorithm for sizing the coal pile runoff pond is:

Pond Area - Acres = (1.05) (Long-Term Coal Storage Area - Acres) (Inches of Rainfall) / [(12) (Average Pond Water Depth - ft)]

where: Inches of rainfall is the amount of rain, in inches, of the 10 year storm. Average pond water depth is the depth of water, in feet, to be in the pond. This should be a minimum of 4 feet.

CHPECON uses the conceptual situation noted above to calculate a pond size for the screening model as follows:

Conceptual Pond Area - Acres = (1.05) (Coal Storage Area - Acres) (0.333) (0.25)

Railroad Track Spur Length

The Railroad Track Spur Length is the linear distance in feet of single railroad track required to store empty and full rail cars. The length does not include space for track switches. This section of the program is utilized when a user selects an option of receiving coal by rail.

The linear feet of single track length is based on railroad clearances published in Table 13 of the Stephens-Adamson Manufacturing Company's *General Catalog Number 66* for 70-ton railroad hopper cars. The track length is based on receiving enough coal three times per week to operate the plant at the plant maximum continuous rating.

The length required for normal average clearance using a standard 4-ft 8.5 in. track gauge for straight track, and must be within the conceptual design requirements. Final design length could change for design clearances due to some railroad companies and states requiring more or less clearance. This length does not include space for track switches, which require additional clearances due to the increase in effective width clearances. The conceptual design estimated track spur length is provided by the following algorithms:

> Railroad Track Spur Length (ft) With Car-Thawing Shed = (Coal @ PMCR - lb/hr) (24 hr/day) (7 days/week) / (3 deliveries/week) (2000 lb/ton) / (70 tons/car) (36 ft/car) (2) + 130 ft
>
> Coal @ PMCR = Amount of coal required by the plant, in lb/hr, with the boilers operating at their maximum continuous rating.

Eighty feet of the rail length is for the car-thawing shed, and should be deducted if the shed is not required.

Weighted Factors

To include nonquantitative factors in evaluating the feasibility of building a new coal-fired heating plant, weighted factors have been included in the program to scale several subjective factors. These subjective factors are evaluated by the response to questions. The allowable responses are listed, and for each response the model explains the consequences of the reply. In addition, a weighted numerical analysis is provided in the output. The program adds these factors at the end of the program. A higher sum is more desirable than a lower one.

Plant Emissions

To determine if the proposed plant will meet emission standards, the plant emissions section calculates the emissions from the plant and compares it to the EMISSION database (Kinast and Blazek, January 1989). To compare the calculated emissions with the EMISSION database, the user must choose a region of a state if requested to do so while running the program.

Nitrogen oxides (NO_x) are produced during combustion by (1) thermal fixation of nitrogen from combustion air and (2) the conversion of organic nitrogen compounds in the fuel to NO_x. For conventional combustors, fuel nitrogen conversion is the main source of NO_x. Over 80 percent of the NO_x in PC combustion is fuel NO_x. Table 5 lists typical emissions of NO_x from PC-fired units without provision for NO_x control. NO_x emissions can be reduced significantly by staged combustion or biased firing.

The combustion of coal produces two types of particulate emissions: (1) fly ash, which is the result of small ash particles being entrained in the flue gas, and (2) carbon particles which result from incomplete combustion of the coal. The composition of particle emissions is strongly related to the type of combustion systems and how the combustor is operated. For example, if coal is fired on relatively undisturbed overfeed or underfeed stoker grates, little ash is entrained as fly ash. Conversely, in PC firing, most of the ash is entrained as fly ash. The carbon emissions are affected by residence time, air/fuel mixing, combustion temperatures, and excess air. To calculate the particulates, SO_x (sulfur oxides) and NO_x (lb/ton of coal burned) out of the boiler, factors were determined for each boiler type and coal type. Table 6 lists these factors.

Table 7 lists the pollution control equipment factors to determine the pollutants out of the gas cleanup equipment. Both tables also list the factors for the various stoker boilers used previously for comparison.

Cogeneration Screening Model

The Cogeneration Plant Screening Model follows the same pattern as the New Heating Plant Screening Model. The following discussion reviews each section of the model, including the inputs required represented in the computer model. The algorithms, where relevant, are also provided.

Plant Site Information

This section is the same as in the New Heating Plant Screening Model.

Table 5. Emissions of nitrogen oxides.

Type of Firing	NO_x (ppm)
Corner Firing	380-550
Front-Wall Firing, Dry Bottom	500-830
Horizontal Opposed Firing	400-1000

Table 6. Pollutant factors – pounds per ton of coal burned.

Boiler Types	Coal Type	Particulates	SO_x	NO_x
Dump Grate Spreader Stoker; Spreader Stokers with Vibrating Grate or Traveling Grave				
- with fly ash reinjection	B, SUB	20A	38S	15
- without fly ash reinjection	B, SUB	13A	38S	15
	L	7A	30S	6
Traveling Grate Stoker; Chain Grate Stoker				
	ANT	1A	38S	10
	B, SUB	5A	38S	15
	L	3A	30S	6
Pulverized Coal	B, SUB	16A	38S	13*

*Based on utilizing low-NO_x burners to achieve 0.5 lb/10^6 Btu

A = Value in weight percent of ash in coal.
S = Value in weight percent of sulfur in coal.
ANT = Anthracite
B = Bituminous
SUB = Subbituminous
L = Lignite

Cogeneration Plant Monthly Loads

The cogeneration plant load demand calculation requires the same information as does the new heating plant screening model: the type of boiler plant to be built (steam only), the average hourly steam demand for each month - lb/hr (hot water - MBtu/hr), and the process steam demand for each month - lb/hr (only for steam). It adds information about the average and peak electrical loads. The user is prompted to input these values and confirm that they are correct before continuing.

Table 7. Pollution contol equipment factors – fractions.

Boiler Type	Setting Chamber	Mechanical Collector	Dry Scrubber	Baghouse
Spreader Stoker	0.8	0.15	0.15	0.005
Traveling Grate Stoker	0.9	0.70	0.15	0.005
Chain Grave Stoker	0.9	0.20	9.15	0.005
Pulverized Coal			0.15	0.005

Cogeneration Plant Maximum Continuous Rating Calculation

The cogeneration plant load demand calculations are based on the PMCR required for heating. The values entered for peak and average electrical demand determine the operating mode for the plant, whether meeting heating demand or electrical demand. However, they have no effect on the PMCR, which is derived only from heating and process loads. For the model, power is generated from turbines operating at steam inlet pressures of 600 psig and an outlet pressure of 150 psig. Additional power can be generated in the summer by the steam not used for heating. A minimum amount of steam equal to 20 percent of PMCR is required to operate the turbine. If this minimum amount is not available, the turbine cannot operate and generate electricity.

Boiler Technology

This section is the same as in the New Heating Plant Screening Model.

Conceptual Boiler Sizing

This section is the same as in the New Heating Plant Screening Model.

Fuel Search

This section is the same as in the New Heating Plant Screening Model.

Water Requirements

This section is the same as in the New Heating Plant Screening Model.

Plant/Boiler Performance Estimates

The Plant/Boiler Performance Estimates are similar to the corresponding section of the New Heating Plant Screening Model, except for the higher steam pressure and related values, as shown in Table 8.

Plant Area Requirements

To determine whether sufficient area is available to build a new cogeneration plant, the model calculates the plant area, coal storage rain runoff pond area, and coal storage areas. The sum of these areas is the total area required to build a new cogeneration plant. Furthermore, the program calculates the plant height, stack

height, and building size for steam facilities of 600 psig and 750 °F using the following algorithms:

Plant Height, ft = (0.11) (PMCR/1000) + 48

Stack Height, ft = (2.5) (Plant Height)

Boiler Size	Building Size (sq ft) 60,000–200,000 lb/hr
3-Boilers	(0.05) (PMCR) + 4,000
4-Boilers	(0.06) (PMCR) + 4,840
5-Boilers	(0.07) (PMCR) + 5,540

The plant includes the boiler plant building, fuel and lime storage, air pollution control devices (baghouses), ID fans, stacks, coal handling, lime handling, ash handling, roads, and parking.

Table 8. Plant performance estimates—ranges and defaults.

Steam S.H. Out Pressure psig	600
Steam S.H. Out Temp, °F	750
Steam S.H. Enthalpy Btu/lb	1378.9
Drum Pressure psig	750
Drum Temp °F	513.1
Drum Saturated Liquid Enthalpy Btu/lb	503.5
Drum Saturated Vapor Enthalpy Btu/lb	1199.55
FW Inlet Pressure psig	800
FW Inlet Temperature °F	325
FW Inlet Enthalpy Btu/lb	295.48

3-Boiler Plant (Acres) = [(0.004) (PMCR) / 1000] + 0.80

4-Boiler Plant (Acres) = [(0.005) (PMCR) / 1000] + 0.83

5-Boiler Plant (Acres) = [(0.005) (PMCR) / 1000] + 1.00

Coal Storage Area

This section is the same as in the New Heating Plant Screening Model.

Fuel Storage Area

This section is the same as in the New Heating Plant Screening Model.

Coal Storage Rain Runoff Pond

This section is the same as in the New Heating Plant Screening Model.

Railroad Track Spur Length

This section is the same as in the New Heating Plant Screening Model.

Weighted Factors

To include nonquantitative factors in evaluating the feasibility of building a new coal-fired cogeneration plant, weighted factors have been included in the program to scale several subjective factors. These subjective factors are evaluated by the responses to questions. The allowable responses are listed, and for each response the model provides an explanation of the reply. In addition, a weighted numerical analysis is provided in the output. The program adds these factors at the end of the program. A higher sum is more desirable than a lower one.

Third-Party Cogeneration Screening Model

The third-party cogeneration screening model is essentially the same as the standard cogeneration screening model. The main difference between the two is that the plant is run at full capacity to generate electricity both for use on the installation and for sale to the outside community.

Plant Maximum Continuous Rating Calculation

The PMCR is determined the same as for a base-only cogeneration plant. However, the value is treated differently when running the facility. Because the third party has the option of selling electricity to the outside, the plant is modeled as running continuously at PMCR. The effect of these changes is reflected in the cost analysis model output.

Third-Party Cogeneration Questions

A number of qualitative questions are asked in addition to those for the standard cogeneration analysis. These questions pertain only to the feasibility of selling electricity externally.

Consolidation Screening Model

The Consolidation Screening Model determines the feasibility of building a central heating plant to replace several smaller heat generators. It analyzes the steam distribution system by questioning the user about the various aspects of the proposed central heating plant. If the analysis indicates that a consolidated central heating plant is a viable option, the user can then evaluate the New Heating Plant Screening and Costing models. After determining the total cost for the consolidated plant, the user may compare it to the sum of the costs for the existing heat generators to estimate the economic viability of a new consolidated central heating plant.

General Information

The format of the information required for the Consolidation Screening Model is the same as for the New Plant Screening Model. The reason for this is that the consolidation model is basically the new plant model, but with the addition of connecting lines for tying together the previously isolated individual lines.

Consolidation Questions

A number of qualitative questions are asked to determine the feasibility of building a centralized heating plant. These questions are asked after the general questions, the same as in the New Plant Screening Model.

4 Equipment Sizing

New Heating Facility

The purpose of this section of the model is to provide the algorithms and designs used to calculate equipment sizes and costs. The major topics covered are:

- Equipment Lists
- Facility Conceptual Layout
- Coal Handling and Storage Equipment Sizing
- Fuel Handling and Storage Equipment Sizing
- Ash Handling and Storage Equipment Sizing
- Dry Scrubber Sizing
- Baghouse Sizing
- Lime Handling and Storage
- Boiler Water Treatment
- Facility Tank Sizing
- Major Facility Fans
- Major Facility Pumps
- Facility Auxiliary Equipment.

Equipment Lists

The major equipment that can be included in a boiler technology design is listed in Table 9. The equipment included in a particular conceptual design depends on a user's inputs and selections made in the costing models.

Facility Conceptual Layout

The conceptual design for a pulverized coal facility is presented in Figures 9, 10, and 11.

Coal Handling and Storage Equipment Sizing

This subsection of the model describes all of the major coal handling equipment and sizing algorithms required to estimate the cost of the equipment. The design configuration depends upon whether coal delivery is by truck or rail, whether a stock/reclaim

Table 9. Major facility equipment.

Coal Handling:

- Rail Car Mover
- Rail-Car-Thawing Shed with Thawing Pit
- Double Track Hopper
- Car Shaker
- Coal Receiving Feeder
- Vibrating Grizzly Feeder
- Double Roll Crusher
- Take Away Belt Conveyor
- Truck Hopper
- Bucket Elevator
- Coal Silo Belt Feeder
- Magnetic Separator
- Reversing Belt Conveyor
- Coal Silo
- Stock Conveyor with Telescoping Chute
- Reclaim Hopper
- Reclaim Feeder Belt Conveyor
- Reclaim Belt Conveyor
- Transfer House Bucket Elevator
- Bunker Tripper Conveyor
- Coal Bunker
- Barge Receiving with Barge Unloader and Belt Conveyor

Ash Handling:

- Bottom Ash Conveying Piping System
- Mechanical Collector Conveyor Piping System
- Dry Scrubber Collector Conveyor Piping System
- Baghouse Collector Conveyor Piping System
- Ash Receiver
- Bag Filter
- Ash Silos
- Air Blowers (to Vacuum-Convey Ash)
- Ash Conditioner (One Per Silo)

Dry Scrubbers:

- Rotary Atomizer Type
- One Scrubber Per Boiler

Baghouse:

- Reverse Air or Pulse Jet Type
- One Baghouse Per Boiler

Lime Handling:

- Storage Silo
- Mechanical Conveyor
- Day Storage Bin
- Mechanical Conveyors
- Lime Feeders
- Lime Slakers
- Grit Screen and Grit Drop Box
- Lime Dilution Tank
- Lime Slurry Pumps

Boiler Water Treatment:

- Sodium Zeolite Softening with Brine Tank
- Brine Wastewater Tank
- Demineralizer with Degasification
- Neutralization Tank
- Acid and Caustic Tank
- Demineralizer with Degasification and Mixed Bed Demineralizer
- Mixed Bed Demineralizer
- Dealkalizer

Water Tanks:

- Condensate Storage
- Treated Water Storage
- Deaerator
- Deaerator Water Storage
- Facility Fuel Oil Storage

Fans:

- Forced Draft (FD) Fans
- Induced Draft (ID) Fans

Pumps:

- Boiler Feedwater, Motor-Driven
- Boiler Feedwater, Turbine-Driven
- Treated-Water Pumps
- Condensate Pumps
- Track Hopper Sump
- Truck Hopper Sump
- Reclaim Hopper Sump
- Neutralization
- Brine Wastewater
- Pond Neutralizer

Air Compressors:

- Plant

Stacks:

- Concrete Chimney with Steel Flues

Blowdown Tanks:

- Continuous
- Intermittent

Chemical Injection Skid

Fire Protection System

HVAC System

Elevator

Facility Controls:
- Boilers
- Yard

Electrical Substation

Continuous Emission Monitoring System:
- SO_2, Nox, and Opacity

Boiler Water Laboratory

Mobile Equipment:
- Front-End Loaders
- Forklift
- Drop Boxes
- Pickup Truck
- Power Sweeper
- Dump Truck

Furniture

Plant Communications

Tools:
- Hand
- Tool Room

Diesel Generator

Spare Parts

Piping

Initial Facility Inventory of Consumables

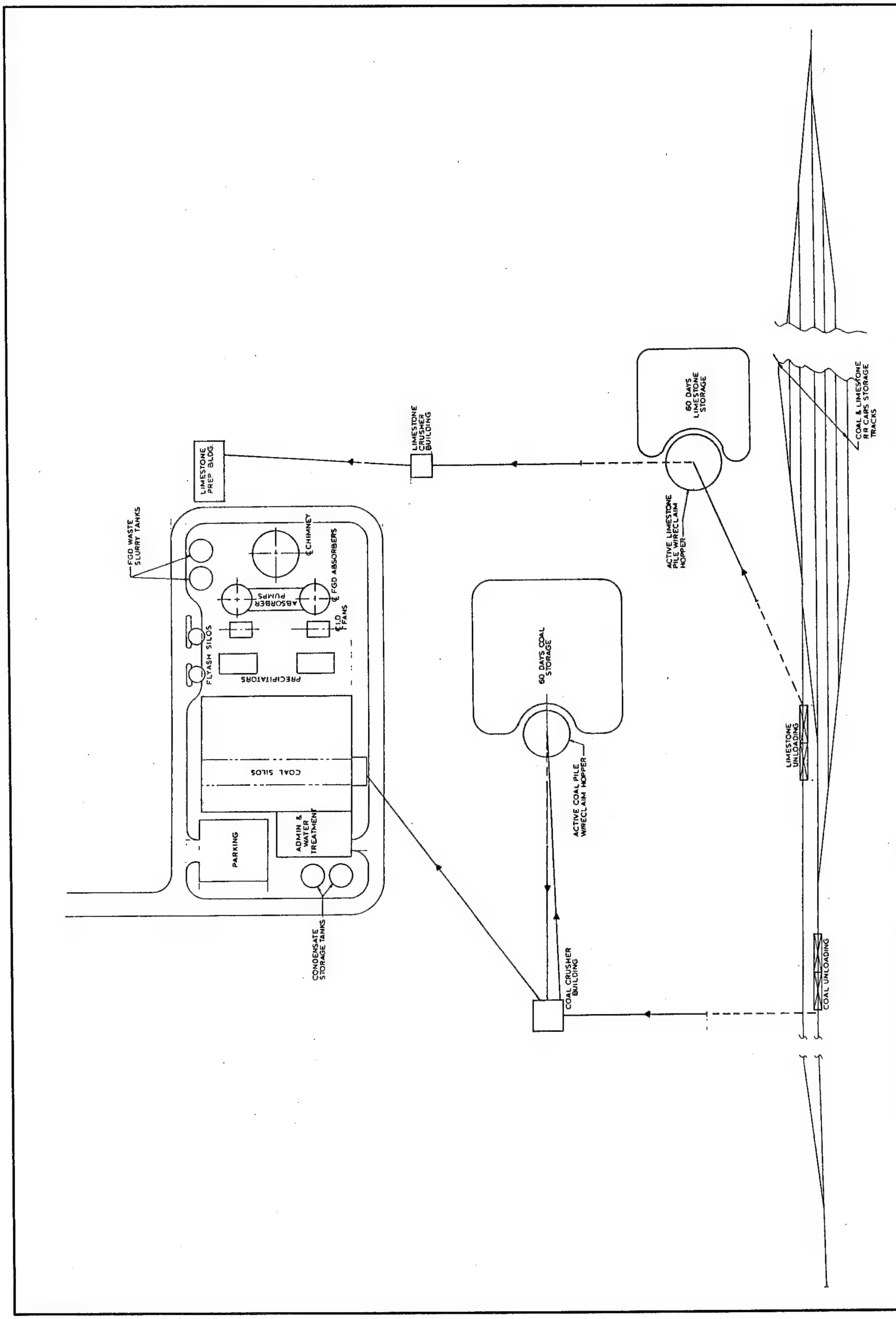


Figure 9. Plant development (using two 200,000–600,000 lb/hr steam generators).

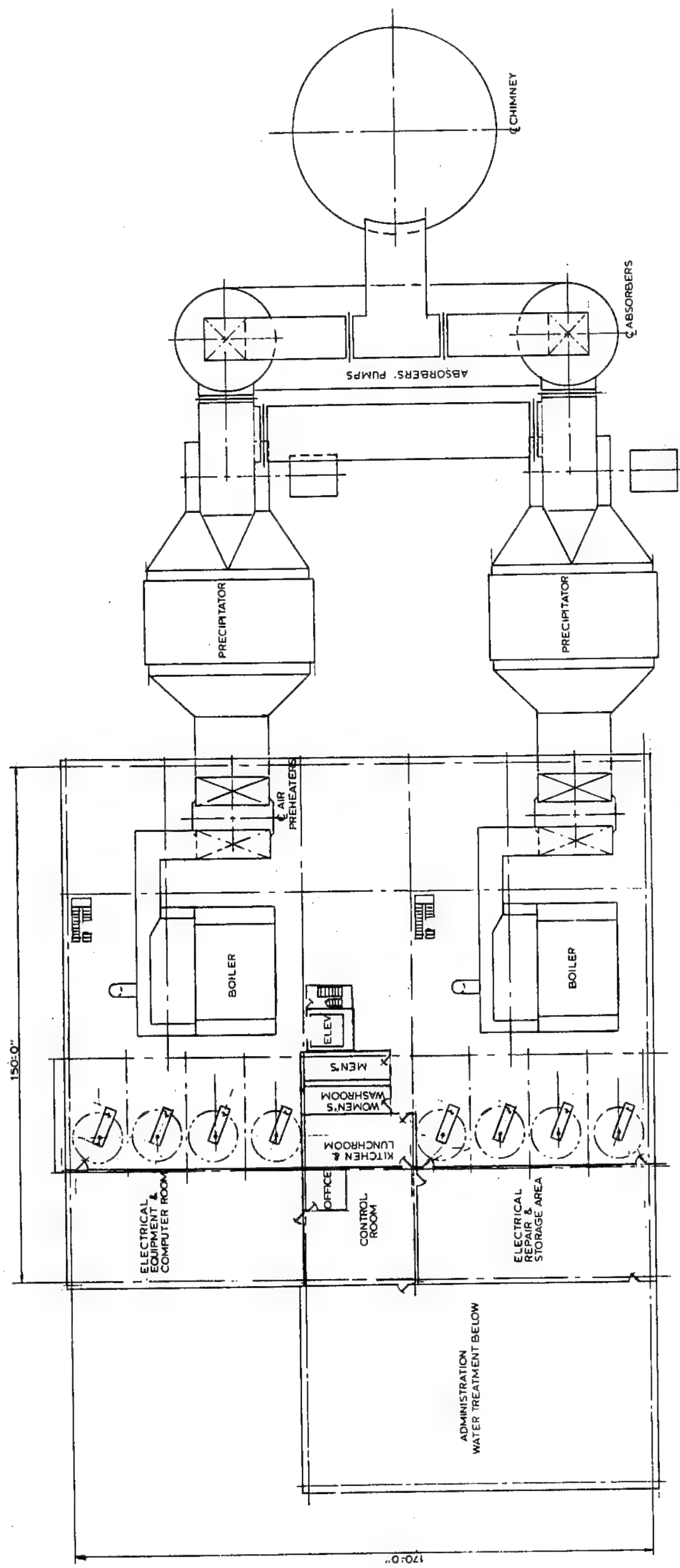


Figure 10. General arrangement plan (using two 200,000–600,000 lb/hr steam generators).

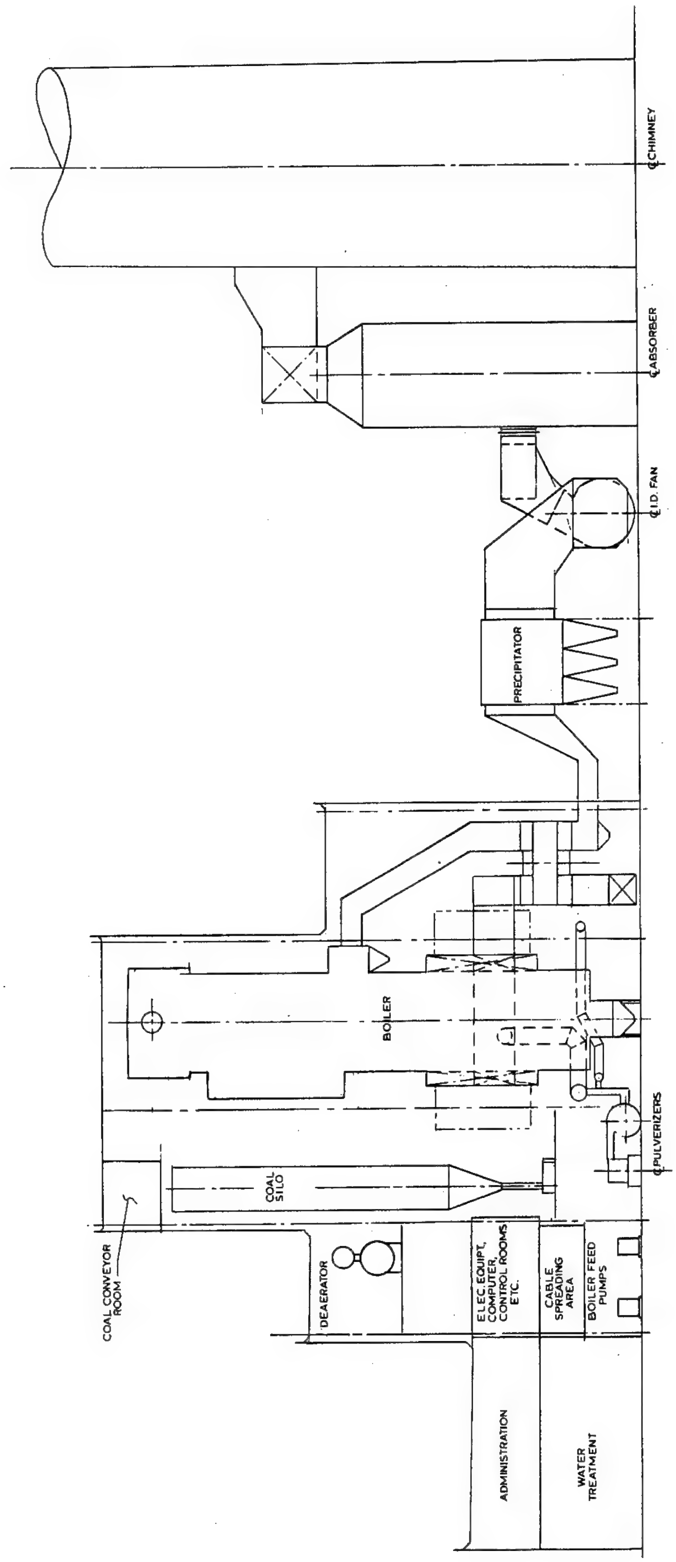


Figure 11. General arrangement elevation (using two 200,000–600,000 lb/hr steam generators).

is used, whether car heating is required, and whether a coal silo is required. The following discussion further explains the coal handling equipment.

Rail Car Mover. A completely reversible, endless rope-type car mover system is used. The items included are double drum with a running rope pull at drums of 18,000 lb and a starting pull of 36,000 lb; 20-hp motor with drive gear; 1400 feet of 1-in.-diameter wire rope with two hitch rope assemblies, and a take-up assembly; stationary bend sheave assemblies, travel limits, guards, track guides, and controls.

Rail Car Thawing Shed. The shed is to be included in the conceptual design when the facility is located or the coal is purchased from a region which experiences freezing conditions for at least 2 months each year. The designed shed is 18 ft wide by 16 ft high by 80 ft long, which is enough for two rail cars. The building is a steel type, and includes four (two per car) light-oil-fired thawing pits, reflector shields, controls, etc. Each thawing pit is rated at 1 million Btu per hour heat input, and uses the following equipment:

- two burners
- steel outer shell
- end plates with cast refractory
- heatshield set
- refractory set
- encased tiles—one with opening for oil pilot
- oil pilot assembly (one per pit) with needle valve and strainer
- burner enclosure (two per pit)
- cover hinged pit with fenders
- interconnecting piping and valves.

Oil distribution piping, regulators, combustion air system, and burner controls are also included with the shed. The facility's auxiliary fuel tank is increased in size to accommodate shed thawing oil requirements.

Double Track Hopper. The conceptual design encloses the rail hoppers in a steel building 18 ft wide by 45 ft long by 18 ft high. Each hopper is constructed of steel, is 13 ft by 28 ft, and has a 40-ton capacity. The hoppers have a top grating of 6-in.-square mesh steel bars with a concrete perimeter. The hoppers include track girders that will support a 100-ton rail car and the bottom of the hoppers have a slide-gate shutoff.

The hoppers are located in a pit approximately 25 ft wide by 45 ft by 35 ft deep. Other equipment located in the pit includes the coal receiving feeders, vibrating grizzly

feeder, double roll crusher, receiving end of the take-away belt conveyor, and a sump pump.

Car Shaker. The car shaker is in the track hopper building described with the double track hopper. The shaker is a stationary installation and includes all necessary equipment for a complete installation, e.g., baseplate, boom, shaker assembly, power unit, hydraulic system, etc. The shaker requires a 25-hp motor for driving the hydraulic unit which shakes the rail car.

The shaker is supported by a boom assembly mounted on baseplates. The purpose of the boom assembly is to retract the shaker outside the rail car clearance line. The boom also extends the shaker until the top shoe is over the side of the car. The shaker is then lowered into place and hangs on the side of the car. The lower hook is then positioned under the car and locked into place and the support cables are slackened. At this point the shaker becomes a part of the car. The valve for the shaker motor is closed and the shaker begins to operate. After the car is unloaded, the shaker is stopped, disconnected, and retracted.

Coal Receiving Feeder. The feeder is a belt-type endless conveyor. The feeder is complete with motor, controls (stop/start), drive system, idlers, belts, skirts, discharge hopper and hood, belt wiper, platform, etc.

Vibrating Grizzly Feeder. The grizzly will be at the discharge end of the coal receiving feeder. The grizzly will screen the coal for size, allowing undersize coal to bypass the crusher. The larger pieces of coal will be fed into the crusher for sizing. The grizzly is complete with bar screen, 3-hp motor, skirts and discharge hopper, controls, etc.

Crusher. The crusher is an adjustable double-roll type for coal sizing. The crusher is complete with 10-hp motor, discharge hopper, controls, etc.

Take-Away Belt Conveyor. This conveyor transports received coal underground from the grizzly/crusher to the bucket elevator. The head end of the conveyor is about 30 ft underground and at the tail or discharge end is about 10 ft underground. The conveyor tunnel is 10 ft wide by 10 ft high, and ends in the bucket elevator shaft pit.

The belt conveyor is 24 in. wide and comes complete with head shaft, tail shaft and take-up, drive and motor, idlers, frame, support, skirts, discharge hopper and hood, belt wiper, controls, etc.

Truck Hopper. The conceptual design encloses the truck hoppers in a three-sided steel building 15 ft wide by 30 ft long, and is 20 ft high in the front and 10 ft high in the

back. The hopper is constructed of steel, is 12 ft by 24 ft, and has a 30 ton capacity. The hoppers have a top grating of 6-in.-square mesh steel bars with a concrete perimeter. The hopper will support a 35 ton truck and the bottom of the hopper has a slide-gate shutoff.

The hopper is located in a pit approximately 15 ft wide by 25 ft long by 25 ft deep. The only other piece of major equipment in the pit is the receiving end of the bucket elevator.

The truck hopper is located next to the coal storage silo if desired, or next to the transfer house.

Bucket Elevator. The bucket elevator receives coal from the take-away belt conveyor and/or the coal silo belt feeder—whichever is applicable—or the truck hopper, and lifts the coal to approximately 12 ft above the reversing belt conveyor. The reversing conveyor is about 3 ft above the top of the coal silo or about 6 ft above the coal bunker tripper belt conveyor.

The bucket elevator is built of steel with "V" type bucket carriers, which are moved by a continuous chain. The elevator is about 3 ft wide and comes complete with "boot" section, drive and motor, controls, bucket and chains, casing, platforms, hoist, and discharge "pantleg" chute.

Coal Silo Belt Feeders. These belt conveyors remove coal from the bottom of the coal silo (one per silo) and discharge the coal into the receiving chute of the bucket elevator. The conveyors are 18 in. wide and come complete with head shaft, tail shaft and take-up, drive and motor, idlers, frame, supports, skirts, discharge hopper and hood, belt wiper, controls, etc. These conveyors are only included with the coal silo option.

Magnetic Separator. The magnetic separator is a permanent rectangular-belt magnet with suspension mounting hardware. A 1-ton-capacity trolley hoist is included along with a tramp iron chute and a box at grade. The separator is at the end of the bucket conveyor and separates iron products from the coal.

Reversing Belt Conveyor. The reversing conveyor receives coal from the bucket elevator and sends it to the coal stock conveyor, a local stock-out pile, or the coal bunker tripper conveyor (depending on the direction of the conveyor and the coal system). The conveyor comes complete with head shaft, tail shaft, reversing gear, drive and motor, controls, frame supports, skirts, etc.

Coal Silos. The coal silos are a selectable option. The silos are steel or concrete stave construction with a flat bottom and come complete with inlet chute, dust collection, outlet neck, slider gate, etc. The silos are sized for a user-specified number of days of coal storage (1 to 7 days each) with the facility operating at the plant maximum continuous rating.

Stock Conveyor. The conveyor is a belt type, about 24 in. wide, and comes complete with head shaft, tail shaft and take-up, drive motor, idlers, frame, supports, skirts, discharge hopper and hood, belt wiper, controls etc. The conveyor is at the coal silo elevation or the bunker tripper belt conveyor and the receiving end is located with the transfer house. The conveyor inclines downward to an elevation of approximately 35 ft above the ground. The conveyor discharges into a telescoping discharge chute above the coal stockout area.

Reclaim Hopper. The hopper is 15 ft square in plan, with top grating of 6-in.-square mesh steel bars. The top of the hopper and grating is formed by concrete that extends 8 ft from each side. The grating is designed to support 50 tons. The hopper is steel. The hopper is located in the ground and in a pit approximately 25 ft square by 25 ft deep. The pit encloses a feeder belt conveyor and the intake end of the reclaim conveyor.

Reclaim Feeder Belt Conveyor. This component is the same as the coal receiving feeder.

Reclaim Belt Conveyor. This conveyor receives coal from the reclaim feeder belt conveyor and moves the coal up to the transfer house bucket elevator. The conveyor is 150 ft long and ends in the transfer house. The conveyor comes complete with head shaft, tail shaft and take-up, drive, motor, idlers, frame, supports, skirts, discharge hopper and hood, belt wiper, controls, etc.

Transfer House Bucket Elevator. This conveyance is constructed the same as the bucket elevator. This elevator is located within the transfer house and elevates the coal about 40 ft to the reversing belt conveyor. The elevator is specified complete with accessories as described with the bucket elevator. This elevator is included only if the user selects a Coal Silo.

Bunker Tripper Conveyor. The tripper belt conveyor receives coal from the reversing belt conveyor and discharges the coal into the coal bunkers above and adjacent to the boilers. The conveyor comes complete with tripper assembly, head shaft, tail shaft, drive, and motor, idlers, frame, supports, skirts, discharge hood, etc.

Coal Bunker. The coal bunkers are located inside the boiler house and are sized for one day's coal storage for each boiler. Each boiler has its own bunker. The bunkers are of steel construction and can, if large enough, have common walls. The bunkers receive the coal via the tripper belt conveyor.

Recommended Coal Handling and Storage Equipment

The following listed coal handling and storage equipment alternatives are suggested for a facility with an adjacent long-term coal storage area:

- Truck receiving, 100 tons per hour (tph) or less
  (No silo, no stockout/reclaim, no thawing shed)
  - — truck hopper with hopper pit and building
  - — bucket elevator with bifurcated chute
  - — transfer house
  - — magnetic separator
  - — bunker tripper conveyor
  - — coal bunker (1 day)

- Truck receiving, 125 to 150 tph
  (No silo, with stockout/reclaim, no thawing shed)
  - — truck hopper with hopper pit and building
  - — bucket elevator with bifurcated chute
  - — transfer house
  - — magnetic separator
  - — reversing belt conveyor
  - — bunker tripper belt
  - — stock conveyor
  - — reclaim hopper with hopper pit
  - — reclaim belt conveyor
  - — transfer house bucket elevator
  - — coal bunker

- Rail receiving up to 150 tph
  (No silo, no stockout/reclaim, with car thawing)
  - — rail track
  - — rail car mover
  - — rail car thawing shed with thawing pits
  - — double track hopper with hopper pit and building
  - — car shaker
  - — coal receiving feeder

- vibrating grizzly feeder
- crusher
- take-away belt conveyor and underground tunnel
- bucket elevator with elevator pit
- transfer house
- magnetic separator
- reversing belt conveyor
- bunker tripper conveyor
- coal bunker (1 day)

- Rail receiving up to 250 tph
  (No silo, with stockout/reclaim, with car thawing)
  - rail track
  - rail car mover
  - rail car thawing shed with thawing pits
  - double track hopper with hopper pit and building
  - car shaker
  - coal receiving feeder
  - vibrating grizzly feeder
  - crusher
  - take-away belt conveyor and underground tunnel
  - bucket elevator with elevator pit
  - transfer house
  - magnetic separator
  - reversing belt conveyor
  - stock conveyor
  - reclaim hopper
  - reclaim feeder belt conveyor
  - reclaim belt conveyor
  - transfer house bucket elevator
  - bunker tripper conveyor
  - coal bunker (1 day)

The following suggested coal handling and storage equipment alternatives are for a facility that does not have an adjacent long-term coal handling storage area:

- Truck receiving, 100 tph or less
  (With silo, no stockout/reclaim, no car thawing)
  - truck hopper with hopper pit and building
  - bucket elevator with bifurcated chute
  - transfer house

- magnetic separator
- single coal silo (3 days)
- coal silo belt feeder
- bunker tripper conveyor
- coal bunker (1 day)

• Rail receiving, 125 to 150 tph
(With silo, no stockout/reclaim, with car thawing)
  - rail track
  - rail car mover
  - rail car thawing shed with thawing pits
  - double track hopper with hopper pit and building
  - car shaker
  - coal receiving feeder
  - vibrating grizzly feeder
  - crusher
  - take-away belt conveyor and underground tunnel
  - bucket elevator with elevator pit
  - magnetic separator
  - single coal silo (3 days)
  - coal silo belt feeder
  - reversing belt conveyor
  - bunker tripper conveyor
  - coal bunker (1 day)

Coal Handling Equipment Sizing

Most of the coal handling equipment is sized, by capacity, on the tonnage of coal required to be received to maintain the facility at PMCR operating conditions. The conceptual sizing factor is based on the ability to unload 3 days of PMCR coal supply within 8 hours. For rail receiving, this equates to three deliveries per week and unloading each delivery within a 6-hour time span, up to a maximum cost utilization rate of about 650 tons per day (tpd), 7 days per week. This provides a coal-handling system maximum receiving rate capacity of 250 tph. The maximum receiving rate is based on the physical limits of being able to unload two and a half 100-ton bottom-dump rail cars per hour, or three 60- or 70-ton rail cars per hour. If the facility requires more coal than 650 tons per day, then the receiving system will operate with increased the unloading times.

The coal-handling equipment is sized by capacity by the following algorithm:

Capacity - Tph =[(Coal @ PMCR - Lb/Hr) (24 Hrs/Day) (7 Days/Wk)]/(3 Deliveries/Wk) (6 Hrs Unload/Delivery)

where: Coal @ PMCR is same as under "Facility Performance Estimates" subprogram
Capacity below 50 tph is 50 tph (Minimum Capacity)
Capacity is to be rounded up to the nearest 25 tph from 50 to 150 tph.
Capacity above 150 tph is to be rounded up to the nearest 50 tph.
Capacity greater than 250 tph is 250 ph (Maximum Capacity)

The coal reclaim system is sized at 100 tph, which almost doubles the amount of coal required by the largest, "worst-case" coal facility. Therefore, to supply this facility, the system would need to be operated approximately 12 hours per day for 7 days per week, or 16 hours per day for 5 days per week.

The coal silos are a user's option. Each is sized by the following algorithm:

Capacity - Tons = (Coal @ PMCR - Lb/Hr) (24 Hrs/Day) (No. of Days Storage) / (2000 lb/ton)

where: Coal @ PMCR - See Facility Performance Estimates Subprogram
No. of Days Storage is a user input value from 1 to 7 days. The default value is 3 days.

Ash Handling and Storage Equipment Sizing

This subsection of the model describes all of the major ash handling and storage equipment. Included in the conceptual design are pneumatic ash conveying (piping) systems, air-operated ash intake valves, a high-efficiency ash receiver (separator), an ash bag filter, three 100 percent mechanical exhausters, an automatic control system, ash storage silos sized for 4 days of ash, and ash conditioners for truck loadup. The model's conceptual ash system design, for sizing purposes, is based on a four-boiler facility. Pickup points for the boiler house vacuum conveying system are each bottom ash boiler outlet and each air heater or economizer settling chamber hopper. Pickup points are also located at each air pollution control device. The ash silos are equipped with a high-efficiency ash receiver with a bag filter for ash removal from the conveying air. The silos are also equipped with a bag vent filter for filtering the air released from the silos during ash filling.

One conveying system can serve multiple boilers, and one ash storage silo can have multiple conveying systems feeding into it. Each conveying system has its own fan, cyclones, and baghouse.

Fly Ash Calculations. The maximum total fly ash out of a PC boiler is 90 percent by weight of the total ash input with the fuel plus an amount of carbon equal to 10 percent, by weight, of the fly ash. This is calculated by:

Total Fly Ash - lb/hr = (0.90) (Ash Input - wt%) (Total Fuel Input - lb/hr) (1.1)

Bottom Ash. The maximum total bottom ash out of a pulverized coal boiler is equal to 30 percent, by weight, as the total ash input with the fuel plus an amount of carbon equal to 10 percent, by weight, of the bottom ash. This is calculated by:

Total Bottom Ash - lb/hr = (0.3) (Ash Input - wt percent) (Total Fuel Input - lb/hr) (1.1)

Ash-Conveying Systems. The ash-conveying systems, boiler, and air pollution control are sized for the facility operating at the PMCR. The ash-conveying systems are sized to convey 3 hours of ash or residue in 1 hour. The maximum size of any single ash-conveying system is 75 tph. If a system is larger than 75 tph, then the system is split into two conveying systems. The scrubber residue conveying system conveys the residue collected in each baghouse. Each baghouse has multiple hoppers. The baghouse residue-conveying system conveys the residue collected in each baghouse. Each baghouse has multiple hoppers. The minimum size of any single conveying system is 2 tph.

All the ash hoppers are sized to hold 12 hours of ash. The hoppers are arranged in such a way that, in an emergency, ash can be spilled onto the floor and removed by hand later. This allows the facility to remain in operation if required. The ash system vacuum pumps are sized for moving the largest required amount of ash. The ash conveying system sizing is calculated by the following algorithms:

Boiler Ash Conveying - Tph = (Total Bottom Ash) (3) / (2000 lb/ton)

Scrubber Ash Conveying - Tph = (Total Scrubber Residue) (3) / (2000lb/ton)

Baghouse Ash Conveying - Tph = (Total Baghouse Residue) (3) / (2000 lb/ton)

Dry Scrubber. Fly ash collected by the dry scrubber is, for ash system sizing purposes, 85 percent of the fly ash out of the boiler. This is calculated by:

Total Fly Ash into Scrubbers - lb/hr = (0.85) (Total Fly Ash)

The dry scrubber residue (ash) system is sized for 50 percent of the total weight of solids into the scrubber. This residue out of the scrubber consists of fly ash, calcium oxide, lime inerts, and calcium sulfate. The residue collected by the scrubber, for sizing purposes, is calculated by:

Total Scrubber Residue - lb/hr = (0.5) [(Total Fly Ash into Scrubber - lb/hr) + (Total Lime - lb/hr)]

Baghouse. The baghouse, for residue collection sizing purposes, will collect 99.5 percent of the total residue into the baghouse. This is calculated by:

Total Baghouse Residue - lb/hr = (0.995) (Total Scrubber Residue - lb/hr)

Ash Silo. The ash silos are flat-bottom type sized to store 4 days of ash and residue calculated at the facility PMCR. Facilities producing up to 175 tpd of ash and residue have a single storage silo. Facilities producing more than 175 tpd will have two ash silos. Each silo supplied will have a high-efficiency ash receiver with a bag filter and bag vent filter. The silo size is calculated by:

Total Residue Collected - tpd [(Ash Input - wt percent) (Total Fuel Input - Lb/Hr) + (0.56) (Total Lime - Lb/Hr)] (24 Hrs/Day) (1.1) (1.05)

where: The 1.05 factor is an estimate of the amount of carbon in the ash. This equation, for conservation in design, uses 100 percent of the fuel ash as being captured.

If total residue collected is equal to or less than 175 tpd, then this value should be utilized for determining the ash silo sizing. If the value is greater than 175 tpd, then the facility should have two silos of equal size, each calculated by using half the total residue collected. The silo capacity and size is determined by:

Minimum Silo Capacity (cu ft) = (Total Residue Collected tons/day) (4 days storage) (2000 lb/ton)/45 lb/cu ft ash)

The silo height is selected to minimize the height while containing at least the minimum silo capacity with the following algorithm:

Actual silo capacity = (height x 3.14 x diameter^2/4)/1.1

where the allowable silo diameters are 12, 14, 16, 20, 30, or 40 ft; the silo height is at least 1.5 diameters but less than 3.5 diameters; and the silo height is 60 ft or less.

Each ash silo will have an individual residue conditioner/unloader. The conditioner wets the residue with water to prevent dust problems and loads the residue into a truck. The conditioner supplied with the conceptual design is determined by the quantity of ash produced by the facility.

If the facility generates 100 tpd or less of ash, the conditioner is a 40 tph unit with a 5 hp motor and uses 60 gpm of water. If the facility generates in excess of 100 tph of residue, each conditioner is a 60 tph unit with a 10 hp motor and uses 75 gpm of water.

Dry Scrubber for Sulfur Control

The boiler facility uses dry scrubbers for sulfur removal. Dry scrubbing systems can achieve at least 90 percent sulfur removal and 70–80 percent acid gas removal. Each boiler uses a dry scrubber and a baghouse. Each scrubber has the necessary processing equipment to mix the boiler flue gases with a reagent for the reduction of acid gases. Each scrubber also includes a rotary atomizer, maintenance hoist, maintenance penthouse above the scrubber vessel, stairs, and platform. The acid gases are recovered by the reaction of lime, (CaO), with the acid gas (SO_2), which forms calcium sulfate, gypsum, and/or calcium sulfite, which is then dried in the vessel. The lime is delivered into the reactor in the form of slaked lime and atomized by the rotary atomizer into fine droplets. The lime delivery and storage system is described under "Lime Handling and Storage" below. The dry scrubbers are sized by the following algorithms:

Scrubber Gas Flow Inlet - lb/hr = (Value calculated) / (No. of Boiler -1)

Scrubber Diameter - ft = [(7.2 x 10^{-5}) (Scrubber Gas Flow Inlet) + 10]

Where the diameter is to be rounded up to the nearest foot.

Scrubber Height - ft = [(2.0 x 10^{-4}) (Scrubber Gas Flow Inlet) + 10]

Where: The height is rounded up to the nearest 5-ft increment.
Minimum vessel height is 50 ft.
Maximum vessel height is 115 ft.

Scrubber Gas Flow Inlet - actual cubic feet per minute (ACFM) = (Value calculated in the Facility Performance Subprogram) / (No. of Boilers -1)

The total dry scrubber system brake horsepower (BHp) is estimated as follows:

BHp = (No. of Boilers) (150 BHp)

Baghouse Sizing

The baghouses are reverse-air-type and have a cloth-to-air ratio of 2:1 with particulate collection efficiency of 99.5 percent. Typically, each boiler is supplied with a baghouse. Each baghouse is compartmentalized and includes inlet and outlet gas flow manifolds, isolation dampers, penthouse, stairs, ladders, platforms, doors, residue hoppers, hopper heating, etc. The baghouses are sized by the following algorithms:

Baghouse Gas Flow Inlet - lb/hr = (Value calculated in the Facility Performance Subprogram)/ (No. of Boilers - 1)

Baghouse Width - ft = [(Baghouse Gas Flow Inlet) (3.337 x 10^{-3}) + 128]/30

where: Depth of the baghouse is 30 ft. Width is rounded up to the nearest whole number 10, e.g., 10, 20, 30, 40 ft, etc.

Baghouse - sq ft = (Baghouse Width) (30)

The baghouse is 60 ft in height for all cases. This allows room for a penthouse, ash hoppers, and the ash conveying lines.

Lime Handling and Storage

The lime handling and storage system receives, stores, slakes three-quarter-inch pebble lime, and supplies the slaked lime to the dry scrubbers. The system consists of:

- A single, 14-day lime storage silo that comes complete with a pneumatic lime fill pipe for receiving lime from a self-powered unloading truck; air fluidization or

bin activation system; and a lime dust vent collection system, installed on top of the silo, for collecting lime dust during silo filling. The minimum lime storage silo has a capacity of 60 tons with maximum silo having a capacity of 3600 tons.

- A mechanical lime conveyor to transport lime from the silo to the lime storage day bin.
- All controls, valves, piping, etc., necessary for a complete system.
- A steel-type air pollution control (APC) building to contain most of the previously described equipment.

The equipment is sized by the following algorithms:

Storage Silo Capacity - Tons = (Total Lime - lb/hr) (24 hr/day) (14 days) (1.1) / (2000 lb/ton)

where: total lime is calculated at PMCR conditions.

Lime Conveyor - Tph = [(Storage Silo Capacity - Tons) / (14) (24)][4]

where: conveyor capacity is based on filling the day bin in four hours.

Day Bin - Tons = (Storage Silo Capacity - Tons)/14

Feeder Capacity - Tph = (1.5) (Lime Conveyor - Tph)
This is also the slaker's lime capacity.

Dilution Tank Size - cu ft = (Total Water to Scrubber - GPM) (60 Min/Hr) (12 Hrs) / (7.48 gal/cu ft)

where: tank size is based on 12 hours of capacity.

Dilution Tank Height - Ft = [(Dilution Tank Size) (4) / (3.14) $(D)^2$] + 2

where: D (diameter) is to be either 4, 6, 8, or 10, such that the diameter-to-height ratio is between 1:1 and 2.5:1.

The total lime system BHp is estimated as a function of lime flow to the dry scrubber, and is provided by:

BHp = (Total Lime - lb/hr) ().015) + 60

where: Total lime is calculated at PMCR conditions.

Boiler Water Treatment

This subsection of the model describes water treating processes commonly used to produce boiler feedwater. The main objective of boiler water treatment is to eliminate or minimize problems caused by impurities in the water and steam. The problems include corrosion, scale, carry-over, and caustic embrittlement.

Corrosion can affect feedwater heaters, boilers, economizers, condensers, piping, etc. Scale reduces heat transfer and causes overheating of boiler tube metal. Foaming and priming cause boiler water carry-over with the steam, which can result in mechanical trouble plus piping deposits. Caustic embrittlement of intercrystalline cracking of metal occurs when the boiler water has embrittling characteristics and is capable of attacking boiler metal.

The choice of a boiler water treatment system design depends on inlet water quality, steam or hot water outlet pressure, steam outlet use, and the amount of water necessary to be added into the system. This is presented only for the design and only as a guide because it is virtually impossible to provide a complete general design that would cover every aspect of water treatment. If a facility is further evaluated, the preliminary design should then be contingent on actual raw water quality, boiler type and pressure, steam usage, operating procedure, blowdown limits, etc.

For screening purposes the following categories are identified:

1. Steam or hot water heating only; less than 625 psig.
2. Steam generation with cogeneration; less than 625 psig and 750 °F.

Each condition requires a different boiler feedwater quality and therefore a different water treatment system. The following water treatment systems are suggestions for the previously specified steam outlet pressures and usage:

- Sodium Zeolite Softening System. This system is used for steam or hot water boiler systems.
- Demineralization with Degasification System. This consists of a strong cation vessel, packed degasifier, and a strong anion vessel. It is used for cogeneration boiler systems.
- Mixed Bed Demineralization. This system can be added to follow one of the previous selections or can be added to clean or polish the steam system's returned condensate.
- Dealkalizer. This can be added to follow the sodium zeolyte softening system equipment to reduce the alkalinity of the softened effluent.

These water treatment designs produce the following boiler feedwater quality:

1. Zeolite: 0-5 ppm hardness as $CaCO_3$, with 200-300 ppm of total dissolved solids (TDS).
2. Demineralization with degasification: 0-1 ppm hardness as $CaCO_3$, with 0-10 ppm TDS.
3. Demineralization with degasification followed by a mixed bed polisher: 0-1 ppm hardness as $CaCO_3$, with 0-2 ppm TDS.

The water treatment equipment described assumes that a good water source (city water system) exists. If the facility under consideration cannot obtain raw water from a good water source system, additional equipment is required. Such additional equipment is as listed below for different sources of water:

- River water
  - — raw water pumps
  - — fire water storage and pumps
  - — chlorinator
  - — river water clarifier system
  - — lime injection system
  - — chemical tanks and injection pumps
  - — acid injection system
  - — filter press and pumps
  - — clear well and pumps
  - — anthracite filters

- Well water
  - — well water pumps
  - — fire water storage and pumps
  - — potable water filter, tank and pumps

- City water
  - — break tank
  - — fire water storage and pumps
  - — city water pumps

Boiler Feedwater System Equipment. The following discussion describes the major equipment.

Sodium Zeolite Softening. The primary purpose of sodium zeolite softening is to remove the scale-forming salts of calcium and magnesium by replacing them with an

equivalent amount of sodium. Sodium zeolite softening is a cation exchange process. This process will produce boiler feedwater with a hardness of 0–5 ppm as $CaCO_3$.

Synthetic polystyrene resins are commonly used for sodium zeolite softening. The fundamental reaction with calcium in this process is:

Ca^{++}	+	Na_2Z	------->	CaZ	+	$2Na^+$
Calcium Ion	+	Sodium Zeolite	---- >	Calcium Zeolite	+	Sodium Ion

When the zeolite resin is exhausted and will not release any more sodium in exchange for calcium or magnesium, the bed must be regenerated. It is regenerated by treating with a 10 percent sodium chloride solution. The regeneration reaction for calcium may be written as follows:

CaZ	+	NaCl	------->	Na_2Z	+	$CaCl_2$
Calcium Zeolite	+	Sodium Chloride	------->	Sodium Zeolite	+	Calcium Chloride

The equipment softener consists of a cylindrical steel pressure vessel with an underdrain resin retention system, and which contains the zeolite (bed) material. The size of the zeolite bed will depend on the exchange capacity of the zeolite, the hardness of water being treated, and the amount of water to be softened between regenerations. The bed must be deep enough to allow proper contact time between the water and zeolite. The flow rate is usually limited to 2–15 gpm/sq ft.
Sodium zeolite softening is required for boiler makeup water except where demineralized water or condensate is the source of all feedwater.

Turbid waters should not be passed through a zeolite softener because accumulated deposits will plug the zeolite bed and reduce its efficiency. Water fed to a zeolite softener should have a turbidity of less than 1 nephelometric turbidity unit (NTU). Municipal water supplies and some well waters meet this low turbidity requirement, and are therefore suitable for zeolite softening. Surface waters tend to be turbid and, in most cases, must be clarified and filtered before zeolite softening. Chlorine (residual) concentration in the water should not exceed 0.3 ppm, to prevent oxidation of the resin. If the concentration of chlorine (residual) is higher than 0.3 ppm, either a sodium sulfite feeder or activated carbon filter is required.

It should be remembered that reduction in alkalinity or total solids does not occur during sodium zeolite softening. Calcium and magnesium ions are removed, but are replaced by sodium ions. With only zeolite-softened water, the raw water alkalinity

concentrates in the boiler. Unless the natural alkalinity is relatively low in comparison with total solids, zeolite softening results in excess boiler water alkalinity and high carbon dioxide concentration in the steam. This condition often requires high blowdown rates to maintain the proper concentration of alkalinity in the boiler, and results in excessive corrosion in condensate lines. High alkalinities are objectionable since they tend to promote boiler water carryover and caustic attack on metal.

Demineralization. Demineralization is the process of removing dissolved matter from water by ion exchange. Demineralization involves two types of ion-exchange resins. Cations such as calcium, magnesium, and sodium are removed by hydrogen-form cation resins. Anions such as sulfate and chloride are removed by hydroxide-form anion resins. Various arrangements of equipment are used, depending upon requirements of the installation and the raw water analysis.

Cation- and anion-exchange resins are available as weak and strong resins. Weak cation resins will remove hardness alkalinity, but will not remove cations associated with chlorides and sulfates. Weak cation resins, when combined with strong cation resins, reduce chemical costs. Strong (acid) cation resins will remove calcium, magnesium, and sodium ions, as well as any other cations.

The weak anion resins will remove sulfate, chloride, and nitrate ions after treatment by a strong acid cation resin, but will not remove silica or carbon dioxide. Weak anion resins, when combined with strong anion resin, reduce chemical cost. Strong anion resins will remove silica and carbon dioxide as well as any other anions.

A decarbonator is provided in demineralization systems after the cation exchanger to remove carbon dioxide when the bicarbonate and carbonate alkalinity of the raw water is greater than 50 ppm. Carbon dioxide can be removed in a decarbonator at much lower chemical cost than it can be removed in the anion exchanger. However, the treated decarbonator effluent still contains 5 to 10 ppm of free carbon dioxide.

In place of the decarbonator, a vacuum degasifier may be used to remove noncondensible gases, including oxygen and carbon dioxide. A vacuum degasifier may be justified for a demineralization plant to eliminate rubber-lined piping for extensive distribution of demineralized water.

Demineralization equipment is similar to that used for hydrogen zeolite softening. The piping and exchanger shells are normally lined with rubber, although stainless steel can be used. Small fittings that cannot be conveniently protected by rubber or plastic linings are made of stainless steel or special alloys. The degasifier tower, which is

used to remove carbon dioxide, is normally rubber-lined carbon steel, with any exposed metal parts made of 316 stainless steel.

Two separate dilution systems for regenerant acid and caustic chemicals are provided to ensure reliability. In addition, neutralization facilities must be provided for the waste regenerant water. Neutralization by batch treatment to pH 6 is required. Hot brine (120 °F) should be provided for periodic treatment of anion resin when organics in the raw water exceed 3 ppm as O_2.

The water temperature with strongly basic anion exchange materials must not exceed 120 °F. Impurities in feedwater to demineralization equipment should not exceed the following levels:

- turbidity—1 NTU
- chlorine—0.3 ppm
- oil—0.3 ppm
- iron—0.3 ppm.

Mixed Bed. Mixed bed is the same process as demineralization. The resins—cation and anion—are together in the same vessel, which is where the term mixed bed is derived. The same type of vessels, pipe, etc., are required.

Dealkalizer. A dealkalizer is a vessel that can be placed after zeolite softening equipment to reduce the alkalinity of the effluent. The buffering of effluent is accomplished through the addition of acid, which is mixed with the effluent in the dealkalizer. This equipment is usually used after and in conjunction with a sodium zeolite softening system.

Water Treatment Equipment Sizing. Equipment sizing is based on the requirement for continuous treated water flow, this being determined by the amount of treated water makeup needed to operate at the PMCR. The makeup depends on the amount of condensate returned to the boiler system, water leakage within the boiler system (packing/steam leaks, deaerator vent steam, etc.), and the boiler blowdown lost. The amount of treated water required is shown by the following algorithm:

Total Treated Water - gpm = [PMCR - lb/hr][1 + (percent Blowdown/100) + (percent Leakage/100) - (percent Condensate Return/100)]/8.33 lb/gal) (60 min/hr)

where: percent Blowdown is a user input
percent Condensate Return is a user input value with a range of 0–100 percent. 50 percent is the default value.
percent Leakage is a user's input value of 0–5 percent with a default of 1 percent.

Number of water treatment trains:

- From 0 to 600 gpm total treated water, the system consists of two, 100 percent trains.
- From 600 to 1200 gpm total treated water, the system consists of three, 60 percent trains.

Treated Water Flow/Train - gpm = (x) (Total Treated Water)

where, for flow rate of:
- 0 to 600 gpm, x = 1.0
- 600 to 1200 gpm, x = 0.6

The amount of water treatment resin is determined with the restriction of 15 gpm/sq ft of resin vessel area. Approximate vessel sizes are determined by:

Resin Vessel Area - sq ft = (Total Treated Water - gpm)/15
Resin Vessel Diameter - ft = SQRT [4 (Resin Vessel Area)/3.1415]

where: Minimum Diameter is 2 ft

Resin Vessel Height - ft = (1.3) (Resin Vessel Diameter)+2.4

Resin Depth - ft = (Resin Vessel Height)/2.215

The total cubic feet (CF) of resin required for the zeolite or demineralizer (not including mixed bed) conceptual design is:

Zeolite or Demin. CF Resin = (Resin Depth) (Treated Water Flow/Train) (No. of Trains) (No. of Resin Vessels/Train)

where: No. of Trains was determined by flow rate
No. of Resin Vessels/Train is determined by
- Zeolite System - 1 Vessel/Train
- Demineralizer System - 2 Vessels/Train

Mixed bed units sizing is provided by the following equations. The conceptual design uses a constant 4 ft of resin depth (2 ft cation and 2 ft anion). The user can input the number of mixed bed units per train.

Mixed Bed Treated Water Flow - gpm = Treated Water Flow/Train

Resin Vessel Area - sq ft = Treated Water Flow/Train/15

Vessel Height - ft = 10 ft

Mixed Bed CF Resin = (4) (Resin Vessel Area) (No. of Trains) (No. of Mixed Beds/Train)

where: No. of Mixed Beds/Train is as input by the user:
Note: one train should be used for cogeneration 625–1200 psig.

Dealkalizer conceptual sizing is based on the maximum water velocity through the vessel of 8 gpm/sq ft. There is one dealkalizer per train.

Vessel Area - sq ft = (Total Treated Water)/8 gpm/sq ft
Vessel Diameter - ft = SQRT [(4) (Vessel Area)/3.14]

where: minimum diameter = 3 ft

Vessel Height - ft = [1.3 (Vessel Diameter) + 3.4]

Dealkalizer Size - cu ft = (Vessel Area) (Vessel Height)

The brine tank is shown below:

Tank Diameter - ft = (0.0083) (Treated Water Flow/Train) + 1.45

where: minimum diameter = 2 ft
Tank Height = 5 ft

The condensate polisher is sized according to the mixed bed equations. The brine rinse surge tank is provided to release the rinse water in a controlled manner.

During regeneration of the sodium zeolite softening system, wastewater is approximately 15 percent of the amount of water treated. The amount of water treated is

approximated by determining the exchange capacity of the resin. This is determined by one of the following two algorithms.

For total treated water of 10–160 gpm:

Exchange Capacity - Grains (Gr) = (1765) (Total Treated Water) + 13,500

(Note: 1 Gr = 0.0648 g.)

For total treated water greater than 160 gpm:

Exchange Capacity - Gr = (5400) (Total Treated Water) - 343,400

Wastewater per regeneration is determined by:

Wastewater/Regeneration - Gal. = [(Exchange Capacity - Gr.)/15][0.15]

Brine Tank Size - cu ft = [(2) (Wastewater/Regeneration) / (7.48 gal/cu ft)][1.15]

where: Tank is used for two regenerations plus 15 percent extra capacity.

For a round tank the diameter selections are 8, 10, 12, 16, or 20 ft.

Tank Height (or Length) - ft = (Tank Size - cu ft) (4) / (3.14) $(D)^2$

The diameter is selected to fit the following restrictions:

- Maximum tank height is 30 ft.
- Tank height-to-diameter ratio is less than or equal to 3.5:1.
- Tank height-to-diameter ratio is at least 1:1.

The neutralization tank accepts the waste regeneration chemicals, acid and caustic, and the rinse water to ensure a neutralized water discharge. The tank size is estimated and sized using the following algorithms.

For the cation vessel:

Cation Treated Water - Gal. = (Treated Water Flow/Train) (1440)

Acid Required per Regeneration - lb = (0.00001) (Cation Treated Water-gal) (15) (17.1)

Acid per Regeneration - Gal = 6(Acid Required per Regeneration - lb)

Backwash Water - Gal = (100) (Resin Vessel Area)

Rinse Water - Gal = (75) (Resin Vessel Area) (Resin Depth - ft)

For the anion vessel:

Caustic Required per Regeneration - lb = (4) (Resin Vessel Area) (Resin Depth - ft)

Caustic per Regeneration - Gal = (3) (Caustic Required per Regeneration)

Backwash Water - Gal = (75) (Resin Vessel Area)

Rinse Water - Gal = (125) (Resin Vessel Area) (Resin Depth - ft)

For the mixed bed vessel:

Acid Required per Regeneration - lb = [(0.00001) (Cation Treated Water) (3) (17.1) (1.02)]

Caustic Required per Regeneration - lb = [(4) (Resin Vessel Area) (2) (1.25)]

Caustic per Regeneration - Gal = (3) (Caustic Required per Regeneration)

Backwash Water - Gal = (75) (Resin Vessel Area)

Rinse Water - Gal = (75) (Resin Vessel Area)

Total Volume of Wastewater Per Regeneration:

Wastewater - Gal = (Cation Acid per Regeneration) + (Cation Backwash Water) + (Cation Rinse Water) + (Anion Caustic per Regeneration) + (Anion Backwash Wash) + (Anion Rinse Water) + (Mixed Bed Acid per Regeneration) + (Mixed Bed Caustic per Regeneration) + (Mixed Bed Backwash Water) + (Mixed Bed Rinse Water)

Tank Size - gal = (2.15) (Wastewater - gal)

where: Tank is sized for two regenerations plus 15 percent.

Tank Size - cu ft = (Tank Size - gal)/7.48

Tank Height (or Length) - ft = (Tank Size - cu ft) (4) / $(3.14)D^2$

where: D = 10, 12, 16, 20, 24, or 30 ft.

The diameter is selected such that the following restrictions are in place:

- Maximum tank height is 50 ft
- Tank height-to-diameter ratio is less than or equal to 3:1
- Tank height-to-diameter ratio is at least 1:1.

Facility Tank Sizing

The facility tanks determined in this section are the condensate storage tank, treated water storage tank, facility acid and caustic tank, deaerator and storage tank, condensate return tank, and facility fuel oil tank.

Condensate Storage Tank. The condensate tank is provided as a surge tank that receives condensate from the heating system return lines. The tank can be sized for a user input of 1 to 4 hours of storage capacity with a default of 1 hour. The tank is a carbon steel, atmospheric tank.

The following algorithms size the tank:

Tank Size - Gal = (Hours of Storage) (percent Condensate Return) (PMCR - lb/hr) / (8.33 lb/gal)

where: Hours of Storage are a user's input value of 1 to 4 hours with a default of 1 hour.
percent Condensate Return is a user's input.

Tank Size - cu ft = [(Tank Size - gal)/7.48 gal/cu ft] (1.15)

Tank Height (or Length) - ft = (Tank Size - cu ft) (4) / (3.14) $(D)^2$

where: D = 6, 8, 10, 12, 16, 20, or 24 ft

The diameter is selected to fit the following restrictions:

- Maximum tank length is 50 ft
- Tank height-to-diameter ratio is less than or equal to 3:1
- Tank height-to-diameter ratio is at least 1:1.

If the storage requirements cannot be met, they are adjusted to fit the maximum size.

Treated Water Storage Tank. The treated water storage tank is provided as a boiler water system surge tank and as a water supply reserve. The tank is sized for 8 hours of storage. The tank is a closed atmospheric tank and is constructed of 316 stainless steel.

The following algorithms size the tank:

Tank Size - Gal = [(8) (PMCR-lb/hr) [1+(percent Blowdown/100)]/(8.33 lb/gal]

where: percent blowdown is a user input from the Facility Performance subprogram.

Tank Size - cu ft = [(Tank Size - gal) / (7.48 gal/cu ft)][1.15]

Tank Height (or Length) - ft = (Tank Size - cu ft) (4) / (3.14) $(D)^2$

where: D = 6, 8, 10, 12, 16, 20, 24 or 30 ft

The diameter is selected to fit the following restrictions:

- Maximum tank length is 50 ft
- Tank height-to-diameter ratio is less than or equal to 3:1
- Tank height-to-diameter ratio is at least 1:1.

If the storage requirements cannot be met, they are adjusted to fit the maximum size.

Acid and Caustic Storage Tanks. These tanks are for the boiler feedwater demineralizer and/or mixed bed treatment system. If the facility has a sodium zeolite system, these tanks are not included in the conceptual design. The tanks are sized to hold approximately one and one-half truck loads.

The acid tank is carbon steel and stores 66-degree Baume strength acid. The tank for the conceptual design is 12 ft in diameter by 16 ft long.

The caustic tank is carbon steel and stores a 50 percent solution, 1.8 specific gravity of caustic (sodium hydroxide). The tank for the conceptual design is 12 ft in diameter by 16 ft long.

Deaerator and Storage Tank. Deaeration is the removal of dissolved gases such as oxygen, carbon dioxide, and ammonia from the treated water before its introduction into the boiler. These gases are undesirable because of their corrosive attack on metal surfaces.

The deaerator is composed of two sections: a deaerating heater and a boiler feedwater storage section. Within the deaerating heater, treated water is deaerated by heating the water to its saturation temperature and scrubbing it with steam to carry away the dissolved gases. The water is then transferred to the storage section by gravity flow. The storage section provides holdup capacity to cover system load swings and emergency situations.

The deaerators are carbon steel and are spray-tray types. The storage tanks, depending on user input, have 5 to 30 minutes of water storage. The default value is 10 minutes of storage.

A three-boiler facility has a single deaerator which is sized for three boiler feedwater flow. The four- and five-boiler facilities have two identically sized deaerators that are each 50 percent of the total plant feedwater flow.

Sizing of the deaerator and storage tank for a three-boiler facility is as follows:

Deaerator Size - lb/hr = (PMCR-lb/hr) [1 + (percent Blowdown/100)]

Deaerator Storage Tank Size - gal= [(Deaerator Size - lb/hr) (Minutes of Storage) / (60 min/hr) (8.33 lb/gal)] (1.07)

where: Minutes of Storage is 5 to 30 minutes, with a 10 minute default.

Deaerator Storage Tank Size - cu ft = [(Deaerator Storage Tank Size) / (7.48 gal/cu ft)] (1.15)

Storage Tank Length - ft = (Deaerator Storage Tank Size - cu ft) (4) / (3.14) $(D)^2$

where: D = 6, 8, 10, 12, 16, or 20 ft.

The diameter is selected to fit the following restrictions:

- Maximum tank length is 30 ft
- Tank height-to-diameter ratio is less than or equal to 3.5:1
- Tank height-to-diameter ratio is at least 1:1.

If the storage requirements cannot be met, they are adjusted to fit the maximum size.

The sizing of the deaerator and storage tank for a 4- 5-boiler facility is as follows:

Deaerator Size - lb/hr = (PMCR) [1 + (percent Blowdown/100)]/2

Deaerator Storage Tank Size - gal = [(Deaerator Size) (Minutes of Storage) / (60) (8.33)] (1.07)

where: Minutes of Storage is 5 to 30 minutes, with a default of 10 minutes.

Deaerator Storage Tank Size - cu ft = [(Deaerator Storage Tank Size) /(7.48)] (1.15)

Storage Tank Length - ft = (Deaerator Storage Tank Size cu ft) (4) / (3.14) $(D)^2$

where: D = 6, 8, 10, 12, 16, or 20 ft.

The diameter is selected to fit the following restrictions:

- Maximum tank length is 30 ft
- Tank height-to-diameter ratio is less than or equal to 3:1
- Tank height-to-diameter ratio is at least 1:1.

If the storage time cannot be met, it is adjusted to fit the maximum size.

Condensate Return Tank. This tank is used as a surge tank for the condensate returned from the steam of an HTHW distribution system. This tank is used before

the condensate polisher or mixed-bed to clean the return before it enters the boiler system. The tank is sized by the following algorithm:

Tank Size - Gal = (Hours of Storage) (percent Condensate Return) (PMCR - lb/hr) / (8.33 lb/gal)

where: Hours of Storage is 1 to 4 hours, with a 1 hour default.
% Condensate Return is a user input.

Tank Size - cu ft = [(Tank Size - gal)/7.48 gal/cu ft] (1.15)

Tank Height (or Length) - ft = (Tank Size - cu ft) (4) / (3.14) $(D)^2$

where: D = 6, 8, 10, 12, 16, 20, or 24 ft

The diameter is selected to fit the following restrictions:

- Maximum tank length is 50 ft
- Tank height-to-diameter ratio is less than or equal to 3:1
- Tank height-to-diameter ratio is at least 1:1.

If the storage time cannot be met, it is adjusted to fit the maximum size.

HTHW Expansion Tank. The expansion tank is provided for the HTHW facility and allows the system to treat the water similar to the deaerator. The tank is sized the same as the deaerator storage tank.

Facility Fuel Oil Tank. The facility fuel oil tank is sized for 12,000 gal of No. 2 fuel oil plus 15,000 gal, which is 1 month's use of oil for the railroad car thawing pits (if the facility is so equipped) plus boiler start-up auxiliary fuel. Therefore, the facility will have one 12,000 gal oil tank or one, 27,000 gal oil tank.

The fuel oil is also used for boiler startup, shutdown and stabilization, and the Diesel-driven fire water pumps, Diesel-driven auxiliary generators, plant vehicles (front-end loaders, trucks, etc.), and the thawing shed (if so equipped).

Major Facility Fans

The major facility fans are the forced-draft (FD fan) and induced draft fan (ID fan). The FD fan supplies air to the windboxes. The ID fans, located after the baghouse and

before the stack, draw the flue gases from the boiler through the downstream equipment.

FD Fan Sizing. The FD fan is sized for 110 percent of the boiler's total design airflow when operating at its maximum continuous rating (MCR). The fan is designed for a static pressure of 20 in. of water, and has a fan efficiency of 70 percent.

Fan Flow - ACFM = (1.1) (ACFM)

where: ACFM = (Wet Airflow, ACFM) / (No. of Boilers - 1) or use the boiler program for one boiler to determine wet air ACFM flow

BHp = [(144) (Fan Flow - ACFM) (3)]/[(33,000) (27.67) (0.7)]

Fan Motor Size - kW = (BHp) (1.15) (0.746).

ID Fan Sizing. The ID fans (one per boiler) draw the boiler flue gas out of the boiler, through such items as the cyclone collector, dry scrubber, and baghouse, then exhaust the gases into the boiler stack flue. The fan is sized for the combustion gases plus air leakage into the boiler, dry scrubber, and baghouse system. For this design, each fan is sized for 100 percent of the flue gas flows plus 15 percent leakage, a static pressure of 20 in. of water, and a fan efficiency of 70 percent.

Boiler Flue Gas Flow - ACFM = [(ACFM) / (No. of Boilers -1)

ID Fan Gas Flow - ACFM = (Boiler Flue Gas Flow) (1.15)

ID Fan-BHp = (144) (ID Fan Gas Flow - ACFM) (20) / (33,000) (27.67) (0.7)

ID Fan Motor Size - kW = (ID Fan BHp) (1.15) (0.746)

Major Facility Pumps

There are four categories of pumps: (1) boiler feedwater pumps (BFWP), (2) plant centrifugal pumps, which include the condensate pumps and the makeup or treated-water pumps, (3) miscellaneous centrifugal sump pumps, which include the rail-track hopper pumps, truck hopper pump, reclaim hopper pumps, neutralization tank pumps, brine wastewater sump pump, and the coal pile runoff pond neutralization pumps, and (4) circulating water pumps. (The chemical feed pumps are addressed under "Chemical Injection Skid" below.)

Boiler Feedwater Pumps. The boiler facility includes two classes of BWFPs: (1) a motor-driven multistage, centrifugal pump, and (2) a steam-turbine-driven multistage, centrifugal pump.

The motor-driven pumps are sized as follows: one pump per boiler up to an individual boiler maximum continuous rating of 150,000 lb/hr, and two pumps per boiler above the 150,000 lb/hr rating. The pumps are volumetrically sized at 10 percent above PMCR. The turbine-driven pumps are sized the same as the motor-driven feed pumps.

The BFWP outlet pressures for both classes of pumps are as shown below:

Boiler Outlet Pressure	BFWP Outlet Pressure
250 psig	300 psig
625 psig	800 psig

The BFWP outlet pressure is appreciably greater than the boiler because of the pressure losses in the piping and the boiler. The BFWPs are complete, and include the pump, pump driver (motor or turbine), baseplate, coupling, and guards. The pumps are sized by the following algorithms:

Motor-driven BFWP for a boiler up to 150,000 pph MCR Pump Size - GPM=[(1.1) (Boiler MCR-lb/hr) (1 + percent Blowdown)/ (8.33 lb/gal) (60 min/hr) (1.2)]

where: Boiler MCR is from the Screening Model under "Boiler Sizing."
% Blowdown is a user's input from the boiler program.
The equation is used for each boiler.

Motor-driven BFWP for a boiler greater than 150,000 pounds per hour (pph) MCR

Pump Size - gpm = ([(1.1) (Boiler MCR-lb/hr) (1 + percent Blowdown)/ (8.33 lb/gal) (60 min/hr) (1.2)])/2

Turbine-driven BFWP Pump Size - gpm = (1.1) (Boiler MCR-lb/hr) (1 + percent Blowdown) / [(8.33 lb/gal) (60 min/hr) (1.2)]

To estimate the BHp of each pump, the following algorithm is utilized:

Pump BHp = (2.13) (Pump Size - gpm) (Pump Outlet Pressure) / (3960) (0.7)

where: Pump Size - gpm is calculated from the appropriate preceding algorithms
Pump Outlet Pressure is as shown in the general pump description.

Motor Size - kW = (Pump BHp) (0.746) (1.15)

Turbine Drive BHp = (Pump BHp) / (0.85)

Plant Centrifugal Pumps. These pump water from various areas of the plant. The treated pumps remove the treated water from the storage tank and deliver the water to the deaerator. The condensate pumps remove condensate from the storage tank and also deliver the water to the deaerator. These pumps are of one- or two-stage design, and the head that they must operate against is largely a matter of piping loss and static-elevation pressure. These pumps are horizontal, end-section centrifugal types with constant-speed motors, and come complete with pump, motor, coupling, baseplates, and guards. There are three treated water pumps and three condensate pumps per facility. The pumps are sized for the design by the following algorithms:

Pump Size - gpm = (0.60) [(1.1) (PMCR - lb/hr) (1 + percent Blowdown) / (8.33 lb/gal) (60 min/hr)]

where: PMCR and % Blowdown are a user's input from the boiler program.
Each pump is sized at 60 percent of the flow rate required to keep the plant operating at the PMCR.

Pump BHp = (2.31) (Pump Size - gpm) (50) / (3960) (.65)

where: The pump has an outlet pressure of 50 psi and an efficiency of 65 percent.

Motor Size - kW = (Pump BHp) (1.15) (0.746)

Centrifugal Sump Pumps. These pumps remove water from the various plant areas. The pumps are sized as follows:

No. of Pumps	Description	gpm	Hp	kW
1	Rail-Track Hopper Sump	150	5	4.3
1	Truck Hopper Sump	300	10	8.6
1	Reclaim Hopper Sump	300	10	8.6
2	Neutralization Tank Pumps	300	10	8.6

2	Brine Wastewater Pumps	150	5	4.3
2	Pond Neutralization Pumps	300	10	8.6

Circulating Water Pumps

The circulating water pumps are high-capacity, low-head type pumps. The pumps circulate the cooled cooling tower water through the turbine condenser and plant auxiliary coolers, and then back to the cooling tower for cooling. The facility conceptual design uses three circulating water pumps. Each pump is sized at 40 percent of the maximum circulating water flow rate and for a 30 psi (70 ft) discharge pressure.

The estimated costs are provided as a function of water flow. The cost includes pump, motor, couplings, and starter. The installation and tie-ins are included in the labor, bulk material, and construction indirect costs. Equipment cost is estimated as follows:

Cost = (4.53) (GPM) + 20,000

Facility Auxiliary Equipment

The equipment presented in this section includes equipment not previously considered that is required for a new PC facility.

Air Compressors. General facility and instrument air compressors are reciprocating or rotary-screw type units. Each compressor is water-cooled and is complete with compressor, motor (V belt or direct drive), guards, intake filters, silencers, oil filter, air receiver, aftercooler, air dryer, etc. The plant has two compressors, each sized for 100 percent of the total load. These compressors are sized by the following algorithms, and produce 125 psig compressed air. (These compressors are not for soot blowing or a bi-fluid dry scrubber; this equipment is included in the boiler and dry scrubber sections.)

Compressor - ACFM = (0.5) (PMCR/1000) + 125

Compressor - Hp = (0.11) (PMCR/1000) + 20

Compressor - kW = (Compressor - Hp) (1.15) (0.746)

Stacks. Facility stacks are freestanding concrete chimneys that enclose steel flues (one flue for each boiler). Depending on the number of boilers, the plant has one or two chimneys. The three-boiler facility has a single concrete chimney which houses three individual boiler flues; the four-boiler facility has two concrete chimneys, each housing

two boiler flues; the five-boiler facility has two concrete chimneys; one chimney housing two boiler flues, and the second housing three boiler flues. The steel flues are insulated, have stack sampling ports, and are independently bottom-supported.

The concrete chimney(s) are freestanding, designed for a wind load of 100 miles per hour (mph) and include testing platforms, a safety ladder to the top, interior and exterior lighting, and Federal Aviation Administration (FAA) lights. Diameters of steel flues are sized by:

Flue Diameter - ft = (0.0001181) (ACFM)

where: ACFM is the total flue gas flow, in ACFM, from a single boiler. This can be approximated by: (Plant ACFM) / (No. of Boilers -1)

Concrete chimney diameter can be estimated by the following:

Two-Flue Chimney Diameter - ft = (0.0001181) (ACFM) (2) + 6

Three-Flue Chimney Diameter - ft = (3.5) (0.0001181) (ACFM)

The height of each concrete chimney is based on the good engineering practice of two and a half times the height of a nearby structure. For the design, the height of the boiler house is used.

Blowdown Tanks. The facility design has two types of boiler blowdown vessels or tanks: (1) the continuous blowdown tank or flash tank, and (2) the intermittent blowdown tank.

Each facility design includes four blowdown vessels, two continuous blowdown tanks, and two intermittent blowdown tanks. The continuous blowdown (flash) tank receives boiler drum blowdown water and flashes the water at a design pressure, with the flash steam being used in the deaerator and the water being sent to the drain. This tank is sized by:

Vessel Diameter - ft = [(0.0367) (0.10) (PMCR - lb/hr) / (2) (1000)] + 0.62

Vessel Height - ft = (3.5) (Vessel Diameter - ft)

The intermittent blowdown tank receives water, on an intermittent basis, from boiler water headers, "mud" drum, etc. This tank, for final design, will be sized in accordance with the American Society of Mechanical Engineers (ASME) Pressure Vessel Code

(ASME, 1 July 1986). For the design, the tank is the same physical diameter size and is three times the height of the continuous blowdown tank.

Chemical Injection Skid. The facility has a single boiler system chemical injection skid. The skid has the equipment necessary to inject chemicals into the boiler drum (phosphates, amines or chelants, and/or anti-foaming agents) and an oxygen-scavenging chemical (hydrazene or other) into the deaerator. The skid has three 55-gal polyurethane mix tanks with agitators, piping, and valves. Included with the skid are six positive-displacement chemical feed pumps, which transfer the chemicals to the boiler drum or the deaerator. The displacement pumps are sized at 0–10 gal per hour and have a discharge pressure of 800 psig. (For higher-pressure units, the drum chemicals would be injected into the feedwater system.) The skid is sized at 14 ft by 12 ft, and has space for all of the previous equipment plus three 55-gal drums of full-strength chemical.

Fire Protection System. The facility's fire protection system is basically a wet-pipe system but the electrical room is protected by an inert-gas system. The wet system includes a separate firehouse; two 1500-gpm at 125-psig Diesel-driven firewater pumps, each with an 8-hour Diesel storage tank; a jockey pump; fire monitors and alarms; plant loop distribution system, sprinkler systems and piping, valves, etc. The inert gas system is a halogen-based system that suppresses fires by oxygen scavenging. The system consists of an inert-gas pressure vessel with a discharge valve.

Heating, Ventilating, and Air Conditioning (HVAC) System. The HVAC system design is confined to the facility's offices, lunchroom, locker rooms, and electrical equipment room. The remainder of the facility is not air conditioned. A 5-ton air conditioner is included for all sizes of facilities. The air conditioner is complete with cooling coils, fans, ductwork, insulation, controls, etc.

The heating system for general facility heating consists of steam or hot water heating coils. The coils are installed with air makeup units in the plant, radiators in the office, lunchroom, locker room, and radiators above doors and below windows, etc.

Elevator. The facility includes one freight/personnel elevator. The elevator is 6 ft by 8 ft inside and will operate from the first floor elevation to the top of the boiler house.

Facility Controls. The control systems for the facility are divided into two basic areas of control: the boiler block and the yard area. The boiler block includes the controls necessary for the boilers, steam header, and boiler-associated equipment or systems. The boiler block control system is a conventional analog or digital control system linking each boiler for total plant control. Each boiler control is configured for single-

loop integrity and has a single control panel for operations overview, with dedicated annunciator windows and motor control, and status indicators. Also included are auto/manual stations for combustion controls, steam outlet controls and switches, and status indicators for the boiler auxiliaries. Each boiler control is interfaced with the total boiler system control for regulation of feedwater, fuel, airflow, desired boiler output, steam control, and proper combustion.

Boiler auxiliary controls include monitoring and control of heat cycle equipment, boiler feed pumps, feedwater system, condensate system, auxiliary electrical system, etc. The yard area controls include flue gas cleaning equipment, boiler water treatment system, wastewater pretreatment system, runoff pond neutralization system, ash-handling system, lime-handling system and the coal-handling system. These controls and monitoring systems are basically independent types of systems for their respective process. Information critical to boiler operations is linked to the boiler controls such that the boiler operators know of potential yard area problems. This scheme physically distributes the total yard control and monitoring systems so a failure of one component does not significantly affect the other yard-area controls.

The makeup water treatment system uses a programmable controller located on the equipment skid. The primary function of the controller is to sequence valve operation for system regeneration. Critical alarms and process variables are transmitted to the boiler block control system using either analog or discrete signal types. The wastewater pretreatment and pond neutralization systems shall use programmable controllers for caustic, coagulant, and acid feed rate and pH control. Each system controller shall also direct the operation of all automatic valves, pumps, mixers, and conveyors associated with the system.

The flue gas cleaning equipment control system for the dry scrubbers; lime receiving, storage, and injection system; and baghouse include a programmable controller for each system. The control panels for each system shall be located near the respective equipment. The ash-handling control system uses a programmable controller that provides the flexibility for automatically adjusting the hopper-emptying sequence in response to varying firing conditions. The coal- or fuel-handling system is a programmable controller that controls the coal conveying system.

Facility Wastewater Treatment. The facility has four types of wastewater flow systems: (1) sanitary waste, (2) process (boiler system) wastewater, (3) storm water, and (4) coal pile runoff pond discharge.

Sanitary waste comprises all waste collected from water closets, sinks, and potable wastewater (such as floor drains in the offices, lunchroom, etc). The design includes

no equipment for treating such waste. All waste is collected and discharged to an existing sanitary sewer system.

Process wastewater is generated by the boiler systems. This is mainly wastewater from the treated-water system, the boiler blowdowns, and equipment cooling water. This water should not contain oil, heavy metals, or other material that would make the wastewater unacceptable for discharge to the sanitary sewer system.

The wastewater from the treated-water system is pretreated in the neutralization tank. This tank neutralizes the wastewater to an acceptable pH value before it is gradually discharged into the sanitary sewer system. As an alternative, the water could be discharged to the coal pile runoff pond, or possibly be used for ash conditioning. The blowdown wastewater from the flash tank is sent to the sanitary sewer.

Other process water, from bearing cooling, facility washdown water, etc., is preliminarily cleaned using dirt-settling chambers and/or grease/oil traps. This wastewater can then be sent to the sewer, runoff pond, dry scrubber system, or used for ash conditioning.

Storm Water. The facility includes a storm water collection system that channels the collected rainwater to an acceptable drainage area. This system also collects the wash water from the ash and coal areas (not including the long-term coal storage area or the truck wash area). The drains located in these areas include appropriate traps or settling basins to collect ash and coal particles.

Electrical Substation. The double ended substation for the facility design includes two main stepdown transformers with oil-filled breakers and other necessary equipment, hardware, wire, etc. The incoming voltage is 13.8 kV and stepped down to a 480 V bus.

Plant Electrical Equipment. The electrical equipment necessary for the facility, includes equipment and other facility breakers, motor starters, relays, wiring, lights, cable trays, conduits, etc.

Continuous Emission Monitoring System. The continuous emission monitoring system (CEMS) provided for the plant continuously monitors SO_2, NO_x, and opacity of the flue gases. This equipment is located in the stack flues near the manual sampling ports. Monitoring equipment is certified and conforms to applicable Federal, state, and local codes. The system has a microprocessor-based remote-mounted control unit. It also provides status, alarms, and information (computer display or hard copy) and has selector buttons that allow an operator to utilize the unit to provide specific data and to change operating/alarm parameters such as set points. The equipment

automatically maintains and generates reports as required by local, state, or Federal agencies.

Boiler Water Laboratory Equipment. Water laboratory equipment is required to perform boiler water quality analysis during boiler operations. The system analyzes the boiler water for such items as oxygen, carbon dioxide, hydrogen sulfide, turbidity, oil, water hardness (all Calcium and Magnesium salts), sodium alkalinity (NaHCO, Na_2CO_3, and NaOH), chlorides (Cl-), sulfates (SO_4--), iron, manganese, silica (SiO_2), oxygen scavenger additive, pH, and scale inhibitor additive.

The system includes all stainless steel tubes, valves, coolers, etc., necessary to extract the water and steam samples and pipe them to a central freestanding water laboratory cabinet. The cabinet comes complete with drain sink, valves, and cabinet areas for the storage of reagents and necessary apparatus. Also included is a workbench or area for use during the water analysis testing.

Mobile Equipment. The design provides mobile equipment for facility operation. The equipment included is as follows:

- Two front-end loaders (four-wheel drive-articulating types), Diesel powered with foam filled tires and a 4 cu yd (6 ton) bucket
- One light-duty front-end loader (four-wheel drive), Diesel powered with foam-filled ties and a 1 cu yd bucket
- One forklift for general plant maintenance (four-wheel drive), Diesel powered with pneumatic tires and rated at 5000 lb capacity
- Two drop boxes provided for lime grit from the slaker and for general plant maintenance, with heavy-duty steel construction, 40 cu yd capacity, drip-proof seals, and can be picked up with a tilt frame (roll-off) truck or other vehicle
- One pickup truck with a three-quarter-ton carrying capacity, Diesel powered with 8-ply tires and meeting all local, state, and Federal safety and emission control devices
- One power sweeper for general internal and external plant maintenance, Diesel powered with the wet/dry cleaning option
- One dump truck for general plant use, with a 5-yard dump body and 5-ton capacity.

Furniture. The new plant includes the necessary furniture and related equipment to furnish the plant offices, lunch room, locker rooms, maintenance shop, boiler operating areas, and other areas that require furnishing. The furniture included in the design includes desks, swivel chairs, two- and four-drawer file cabinets, bookcases, side

chairs, stacking chairs, lunchroom tables, benches and cabinets with countertops, lockers, locker room benches, supervisor floor desks, metal storage bins, racks, etc.

Plant Communications. The plant includes a telephone system with telephone stations, attendant console, private automatic branch exchange (PABX), amplifiers, battery, battery charger, paging speakers and horns, wiring systems, and all conduit necessary. Units installed in high-noise areas are provided with acoustic booths and noise-limiting devices on the telephone receiver. Other features included with the system are direct station-to-station calls within PABX without attendant assistance, direct outward dialing for outside and long-distance calls, direct access to paging system, night answering, and call forwarding.

Tools. A new facility basically requires two types of tools: hand tools (for equipment and maintenance) and major tool room equipment (such as metal lathes, grinders, welders, drill stands or presses), hydraulic press, milling machine, etc.

Building. The only building for the stoker boiler facility is the boiler house. This houses the boilers and associated equipment, and includes the plant's office, lunchroom, men's and women's locker rooms, plant maintenance, and stores. Other enclosed areas (ash loadup room, scrubber penthouse, maintenance, etc.) are included with the equipment. The boiler house size is estimated by algorithms described in Chapter 3. The building is metal-sided, with power roof vents, windows, personnel doors, and vehicle roll-up doors. Included with the building are building steel, siding and roof with insulation, stairs, ladders, floors, grating, etc.

Diesel Generator. The Diesel generator is required for onsite backup or emergency electrical power. The units range from 100 to 1500 kW in size, and are skid-mounted, standalone units. The Diesel generator is sized by adding the major equipment BHp or kW, then multiplying by a factor of 0.25 up to a maximum of a 1500 kW generator.

Piping. The plant piping system includes high-, medium-, and low-pressure steam, exhaust steam, steam system supply, steam return, condensate (plant and return), city process water, city potable water, treated water, feedwater, boiler blowdown, sanitary drains, roof drains, process water drains, storm water drains, plant heating system, fuel oil piping, chemical piping, compressed air piping, etc. During preliminary design using a specific facility, the major piping systems must be addressed, and possibly a preliminary design should be executed.

Spare Parts. Spare parts for major equipment and systems are required for a new facility. These parts are usually defined as a capital expense during operation of a facility and need to be included in the cost estimate.

Initial Facility Inventory. A new facility must start with an initial inventory of consumables. These items are normally considered as yearly operational needs, but a new facility must have an initial inventory to begin operations. Items included in this category are packing seals, grease, oil, small parts (bearings, valves, pipe, fittings, etc.), rags, light bulb, buckets, mops, cleaning agents, towels, etc.

New Cogeneration Facility

The purpose of this section is to describe the algorithms and designs that are used to properly size the plant for cogeneration. It does not cover the material already discussed under New Heating Facility because, conceptually, the cogeneration facility is simply a heating facility with additional equipment for generating electricity. The following sections discuss the major equipment and facility conceptual layout.

Equipment Lists

The major equipment list for a cogeneration plant includes all equipment required for a new heating plant, with the addition of a turbine-generator, condenser, cooling tower, circulating water pumps, and feedwater heaters.

Turbine-Generator

The cogeneration facility utilizes a single extraction-condensation turbine-generator to generate electricity and provide plant heating system and process steam. The 600 psig and 750 °F steam turbine has a maximum of two steam extractions. The extractions are 170 psig, which are used for the heating system, possibly a feedwater heater and/or process steam, and a 35 or 50 psig extraction for feedwater heating. Total allowable steam extraction is maximized at 80 percent of full turbine throttle flow steam rate. (PMCR for the conceptual design is full turbine throttle flow.) This allows a minimum of 20 percent flow to the turbine exhaust stages for proper cooling of the turbine. The turbine is designed for full flow condensing. The 600 psig, 750 °F turbine steam condition utilizes two types of turbines:

1. For throttle flows from 60,000 to 100,000 lb/hr, the turbine-generator is a skid-mounted gear type unit with the steam extractions and exhaust exiting up. This allows the condenser to be on the same floor level as the turbine.
2. For throttle flows from 100,000 to 600,000 lb/hr, the turbine-generator is a direct-drive unit with the steam extractions and exhaust exiting down. The condenser is installed below the turbine on a separate floor.

The suggested turbine–regenerative feedwater heating system utilizes the following equipment:

1. For throttle flows from 60,000 to 100,000 lb/hr, the design utilizes the deaerator at 20 psig for feedwater heating.
2. For throttle flows from 100,000 to 250,000 lb/hr, the design utilizes a low-pressure heater, a low-pressure feedwater heater, and the deaerator at 50 psig for feedwater heating.
3. For throttle flows from 250,000 to 600,000 lb/hr, the design utilizes a low-pressure feedwater heater, a 20 psig deaerator, and a high-pressure (120 to 150 psig) feedwater heater.

The generator is a 3-phase, 60 cycle, synchronous air-cooled type with brushless exciters. The generator is rated at 13.8 kV and 150 MVA (Megavolt-Amphere), with a power factor of 0.85. The turbine-generator comes complete, including:

- steam turbine
- electrical generator
- exciter
- voltage regulator
- hydraulic governing system
- control and lubricating oil system
- turbine gear - manual and automatic
- turbine control
- gland sealing system
- bearings
- coupling and coupling guard
- extraction non-return valves
- baseplate
- protective devices
- supervisory instruments
- generator cooling systems.

The turbine-generator is sized in megawatts (MW) using full-throttle flow condensing.

PMCR @ 600 psig & 750 °F - Condensing MW = (0.1084) (PMCR/1000)

Condenser

The condenser is a two-pass, shell-and-tube surface type sized for full turbine throttle flow condensing at 2.5 in. HgA or 3 in. HgA, depending on the steam turbine system. The condenser comes complete, including:

- condenser with air removal section
- hotwell for 5 minutes of storage
- split water boxes, inlet and outlet
- drains, makeup and relief connections
- piping, valves, and fittings
- expansion joint, condenser to turbine
- air removal equipment including mechanical vacuum pump
- steam jet air ejector (SJAE) with inter- and after-condensers.

The condenser is sized by the following algorithms:

Tube Surface - sq. ft = PMCR/10

Condenser Length - ft = 0.3(PMCR/10,000)

Condenser Dia. - ft = [(0.136) (PMCR/10,000) + 9]

Condenser Height - ft = [(0.136) (PMCR/10,000) + 9] +1.5

Cooling Tower

The cooling tower is provided to cool the main condenser and plant auxiliary systems. The tower is designed for a mid-continent location (State of Tennessee) and for a 1 percent wet bulb condition. The tower is a multicell induced-draft counterflow evaporative type mounted on a concrete basin and foundation.

The cooling tower comes complete with:

- structural framework
- equipment supports
- water distribution system and valves
- mechanical equipment, including fans, reducing gears etc.
- motors and starters
- stairways, ladders, platforms and handrails
- modular fill

- electrical wiring and conduit
- fan deck
- fan stack(s)
- hot water main header and riser
- instruments and controls
- water makeup system
- chemical treatment system
- fire protection
- blowdown system

The cooling tower is sized using the following design factors:

- tower heat load equals condenser duty plus 10 percent for auxiliary cooling
- cooling water has a 20 °F temperature difference
- cooling tower operates at five cycles
- each cooling tower cell is approximately 40 ft high, 45 ft wide, and 50 ft long
- condensing heat load of full turbine throttle flow.

Condenser Cooling Water Flow - gpm = (PMCR) (1010 Btu/lb) / (20 Btu/lb water) (60 min/hr) (8.33 lb/gal)
Circulating Water Flow - gpm = (1.1) (PMCR) (1010 Btu/lb) / (20 Btu/lb water) (60 min/hr) (8.33 lb/gal)

where: maximum tower cell size is 17,000 gpm circulating water flow.

No. of Cells = (Circulating Water Flow - gpm)/17,000

where: No. of Cells is rounded up to the nearest whole number.

Evaporation - gpm = (Circulating Water Flow - gpm) (0.014)

Blowdown - gpm = (Evaporation - gpm) (0.20)

Makeup - gpm = (Evaporation - gpm) (1.2) + (0.001) (Circulating Water Flow - gpm)

Cooling Tower Length - ft = (No. of Cells) (50)

Cooling Tower Fans (one per cell) are sized by:

Tower Airflow - ACFM = (Circulating Water Flow - gpm) (18.017)

Tower Fan Flow - ACFM = (Tower Airflow - ACFM) / (No. of Cells)

Tower Fan BHp = (Tower Fan Flow - ACFM) (0.0004)

Tower Fan Motor Size - kW = (Tower Fan BHp) (.8579)

Total Tower Fan - kW = (Tower Fan Motor Size - kW) (No. of Cells)

Circulating Water Pumps

The circulating water pumps are high-capacity, low-head type pumps. The pumps circulate the cold cooling tower water through the turbine condenser and plant auxiliary coolers then move it back to the tower for cooling. The facility uses three circulating water pumps. Each pump is sized at 40 percent of the maximum circulating water flow rate and for a 30 psi (70 ft) discharge pressure. The circulating water pumps are sized by:

Total Pump Capacity - lb/hr = (7.915) (PMCR)

Pump Capacity - gpm = (7.915) (PMCR) (0.40) / (499.8)

Pump BHp = (2.31) (30) (7.915) (PMCR) (0.40) / (499.8) (3960) (0.70)

Pump Motor Size -kW= (1.15) (0.746) (2.31) (30) (7.915) (PMCR) (0.40) / (499.8) (3960) (0.70)

Feedwater Heaters

The feedwater heaters are used in the cogeneration regenerative feedwater heating cycle to heat the feedwater prior to the water entering the boilers. The 600 psig, 750 °F cogeneration system utilizes the following configurations:

- for turbine throttle flows from 60,000 to 100,000 lb/hr, the system does not include a feedwater heater—the deaerator preheats the feedwater
- for throttle flows from 100,000 to 250,000 lb/hr, the system has a single low-pressure heater operating at approximately 20 psig—the deaerator also preheats the feedwater and operates at about 50 psig.
- for throttle flows from 250,000 to 600,000 lb/hr, the conceptual system utilizes a low-pressure heater at about 10 psig and a high-pressure feedwater heater

operating at about 120 to 150 psig—the deaerator also preheats the feedwater operating at about 20 psig.

The number of feedwater heaters selected for this design was based on an optimum temperature to which the feedwater can be heated. When this limit is exceeded, the amount of work delivered by the extracted steam reduces the benefit to the cycle. Furthermore, overall plant economy limits the maximum feedwater temperature. When the feedwater is heated to a higher temperature because of the increased number of feedwater heating stages, the water-gas temperature difference available to the economizer becomes less; therefore, less heat will be extracted from the flue gases. This can result in an increasing stack loss and thus a decrease in boiler efficiency, which may negatively outweigh the improvement of the turbine cycle. As a rule of thumb, for 600 psig and 750 °F cogeneration cycles, the favorable feedwater final temperature (before to entering the boiler/economizer) is about 240 °F for one stage of heating; 280 °F for two stages of heating; 315 °F for three stages of heating, and 350 °F for four stages of heating. The feedwater heaters are sized by the following factors and algorithms:

For low-pressure heaters less than 50 psig operating pressure:

Surface Area - sq ft = (Total Treated Water - gpm) (0.00061)

where: Total Treated Water is calculated in the boiler feedwater section.

Effective Tube Heating Length - ft = (2.25×10^{-5}) (Total Treated Water - gpm) + 6.5

Shell Diameter - ft = (0.1167) (Surface Area) / (Effective Tube Heating Length)

Heater Length - ft = [(Effective Tube Heating Length - ft)/2] + 3

For high-pressure heaters less than 175 psig operating pressure:

Surface Area - sq ft = (Total Treated Water - gpm) (0.00168)

Effective Tube Heating Length - ft = (7.273×10^{-5}) (Total Treated Water - gpm) + 4

Shell Diameter - ft = (0.167) (Surface Area) / (Effective Tube Heating Length)

Heater Length - ft = [(Effective Tube Heating Length - ft)/2] + 3

For high-pressure heaters less than 350 psig operating pressure:

Surface Area - sq ft = (Total Treated Water - gpm) (0.002)

Effective Tube Heating Length - ft = (7.273×10^{-5}) (Total Treated Water - gpm) + 5

Shell Diameter - ft = (0.167) (Surface Area) / (Effective Tube Heating Length)

Heater Length - ft = [(Effective Tube Heating Length - ft)/2] + 3.5

5 Capital Costs

This section of the model includes the cost equations used to determine the capital cost for new PC-fired steam production and cogeneration power plants. The major equipment costs are broken into subsections.

After the equipment costs are determined, these costs are added to the freight and direct installation costs. Finally, the indirect costs are added to complete the boiler plant cost. These costs are further discussed after the discussion of each of the equipment costing subsections.

Major facility equipment cost subsections:

- Boiler
- Coal Handling
- Ash Handling
- Dry Scrubber and Lime System
- Baghouse and ID Fan
- Boiler Water Treatment
- Tanks
- Pumps
- Air Compressors
- Wastewater Treatment
- Piping
- Instrumentation
- Electrical
- Building and Services
- Site Development
- Spare parts, tools, mobile equipment

Additional subsections for cogeneration:

- Condenser
- Cooling Tower
- Feed Water Heater
- Turbine Generator

Additional subsection for consolidation:

- Steam Distribution System

Boilers

The Boiler subsection includes cost estimates for the boiler. The scope of supply includes:

- boiler pressure parts and drums
- boiler trim and soot blowers
- boiler refractory, insulation and lagging
- FD fan
- combustion air ductwork and distribution system
- superheater, if applicable, with attemperator
- boiler convective sections
- economizer
- main steam nonreturn and block valve
- coal pulverizers
- coal feeders
- coal distribution duct
- coal scale
- fly ash reinjection system
- ash hoppers
- boiler steel
- boiler instruments
- freight
- erection and erection supervisor
- startup supervision
- boilout and initial operator training
- operation manuals.

Excluded from the boiler costs are items such as foundations, tie-ins for electrical systems, controls, and piping to and from the boilers. These items are part of the associated installation costs listed as labor, bulk materials, and construction indirect costs.

The boiler cost equations are all linear and are shown as a function of the steam production rate or boiler MCR. The cost equations are based on bituminous coal.

The boiler estimated costs are a function of outlet steam pressure and temperature and steam flow (MCR). The following cost equations provide an estimate of capital costs for both PC boilers and pulverizer equipment.

1. 250 psig Saturated Steam
   Range up to 200,000 lb/hr
   Cost = [(0.025) (MCR/1000) + 0.73] Million
2. 600 psig & 750 °F Steam
   Range up to 200,000 lb/hr
   Cost = [(0.025) (MCR/1000) + 1.01] Million

Coal-Handling System

To determine coal-handling system costs, the program requires the user to input whether rail or truck will be used, if a stock/reclaim system should be included, if car heating is required, if a coal silo is required and if so, how many days of storage is required for the coal silo. The estimated costs are calculated for each main system component.

Truck Receiving

Cost - $ = 5000(tph) + 100,000

where: tph is tons per hour
Minimum Cost = $350,000
Maximum Cost is @ 150 tph

System does not include stock/reclaim system or silo.

Truck Receiving With Stock/Reclaim

Cost - $ = 6550(tph) + 140,000

where: tph is tons per hour
Minimum Cost = $450,000
Maximum Cost is @ 150 tph

System does not include silo.

Rail Receiving

Cost - \$ = 2400(tph) + 775,000

where: tph is tons per hour
Minimum Cost = \$1,000,000
Maximum Cost is @ 250 tph

System does not include silo, stock/reclaim system, or car heating.

Rail Receiving with Stock/Reclaim

Cost - \$ = 4350(tph) + 760,000

where: tph is tons per hour
Minimum Cost = \$1,200,000
Maximum Cost is @ 250 tph

System does not include silo or car heating.

Car Heating

Cost - \$ = 367(tph) + 23,000

where: tph is tons per hour
Minimum Cost = \$50,000
Maximum Cost is @ 250 tph

Coal Silo

Cost - \$ = (Tons of Storage) - 40,000

Car Dumper

The car dumper installed cost is estimated at \$2.2 million. This includes rotary car dumper, house, positioners, pit, railroad over pit, and coal hopper.

Railroad

The railroad cost is \$85 per linear foot of railroad track.

Coal Pile Runoff Pond

The pond receives storm water runoff from the long-term coal storage area. TM5-848-3 requires the pond to be sized to contain the runoff from a 10-year, 24-hour storm with 2 ft of freeboard. The sizing method uses an average pond water depth of 4 ft and sizes the pond for 4 in. of rain in 24 hours, with no absorption. The pond cost is estimated at $1200 per 1000 square feet or $1.20 per sq ft. The major cost items are excavation and liner costs.

Ash Handling

The ash removal and handling system is a pneumatic ash system. Included in this system is the pneumatic ash conveying system (piping); air-operated fly ash intake valves; manually-operated bottom ash intake valves; air-operated branch line gates; mechanical exhausters with motors, snubbers, temperature and vacuum gauges, a vacuum-relief valve and dust detectors; and ash receiver/bag filter with valves and double vacuum breaker. The size and thus cost of the system is based on the amount of ash in the fuel, boiler type, and other equipment (dry scrubbers) that add material to be handled by the ash system.

The amount and location of ash (bottom ash collector, dry scrubber, etc.) determines the ash system size. The system size determines its cost along with the size and cost of the mechanical exhausters and ash receiver. These costs, along with the ash silo and control system costs, are summed to determine the total ash system costs. The ash system costs are derived by the following equations:

Ash Pipe Length Estimate

Equation A: Bottom Ash Pipe Length - ft = (Bldg. Length - 25) + (Bldg. Width + 15) + (Ash Silo Height + 25)

where: Bldg. Length and Width are calculated by the following formulas:

For three boilers

Width of Building - ft = [(0.1) (PMCR)/1000)] + 50
Length of Building - ft = [(0.11) (PMCR/1000)] + 150

For four boilers

Width of Building - ft = [(0.11) (PMCR)/1000)] + 50
Length of Building - ft = [(0.1) (PMCR/1000)] + 220

For five boilers

Width of Building - ft = [(0.11) (PMCR)/1000)] + 50
Length of Building - ft = [(0.1) (PMCR/1000)] + 210

Equation B: Scrubber Residue Ash Pipe Length - ft = (Bldg. Length) + (Ash Silo Height + 25)

Equation C: Baghouse Residue Ash Pipe Length - ft = (Bldg. Length) + (Ash Silo Height + 25) + [(No. of Boilers) (Baghouse Size + 30'-15')

Branch Line Gates

Equation D: Number of Gates = (No. of Boilers) + 4

3-Blr. Hse.: Gates = 7
4-Blr. Hse.: Gates = 8
5-Blr. Hse.: Gates = 9

Fly Ash Intakes

Equation E: (No. Blrs.) [2 + (0.6) (Baghouse Approx. Sizing)]

Bottom Ash Intakes

Equation F: (No. of Blrs.) (2)

Ash Pipe System Size

Bottom Ash

Equation G: Pipe Size = (0.1143) (tph) + 5.42

where: If less than 5 tph, then Pipe = 6 in.
If greater than 40 tph, then pipe = 12 in.

Eqn. To be rounded up to nearest whole number
tph = (Bottom Ash) (3)/2000.

Fly Ash (Scrubber Residue, Baghouse)

Equation H: Pipe Size = (0.1667) (tph) + 3.66

where: If less than 2 tph, then = 4 in.
Range 0 – 20 tph
Eqn. to be rounded up to nearest whole number.

Equation I: Pipe Size = (0.08) (tph) + 5.8 - Range 20 to 40 tph

Equation J: Pipe Size = (0.086) (tph) + 5.55 - Range 40to 75 tph

Pipe Cost

Equation K: Bottom Ash Pipe Cost - $/ft = (Eqn. G) (8.75) + 25

Equation L: Fly Ash Pipe Cost - $/ft = (Pipe Size) (8.75) + 25

where: Pipe Size = Eqn. H, I, or J.

Ash Pipe System Cost - $

Equation M: Bottom Ash Pipe - $ = (Eqn. A) (Eqn. K)

Equation P: Scrubber Residue Ash Pipe - $ = (Eqn. B) (Eqn. L)

Equation Q: Baghouse Residue Ash Pipe - $ = (Eqn. C) (Eqn. L)

(Note: Equations N and O, developed as part of the overall plant costing model, do not apply to PC-fired central energy plants.)

Total Ash Piping System Cost

Equation R Cost - $ = Eqn. M + P + Q

Air-Operated Branch Line Gate Cost/Gate

Equation S: Bottom Ash System - Gate Size Costs - $ =

1. Gate Cost = (33.333) (Eqn. H) + 1200
where: Eqn. H = 6 in. - 9 in.

2. Gate Cost = (250) (Eqn. H) + 1000
where: Eqn. H = 10 in. - 12 in.

Equation T: System Gate Size Cost - $: or
Scrubber Residue - Gate Size Cost - $: or
Baghouse Residue - Gate Size Cost - $:

Equation T.1: Cost = (Eqn. I, J, or K) (200) + 200

where: Eqn. I, J, or K = 4 in. - 6 in.

Equation T.2: Cost = (Eqn. I, J or K) (33,333) + 1200

where: Eqn. I, J, or K = 6 in. - 9 in.

Equation T.3: Cost = (Eqn. I, J, or K) (250) + 1000

where: Eqn. I, J, or K = 10 in. - 12 in.

Air-Operated Branch Line Gate Costs

Equation U: Cost $ = (Eqn S 1 or 2) (2) + (Eqn T 1 or 2 or 3) (2) + (No. of Boilers)

Air-Operated Fly Ash Intake Cost - $

Equation V: PC Boiler - $ = (Eqn. F) (1400)

Manual Bottom Ash Intake Cost - $

Equation W: Cost - $ = (Eqn. G) [(Eqn. H) (62.5) + 125]

Mechanical Exhauster Cost - $

Equation X: Cost - $ = [(Eqn. H) (6872) - 7500] (3)

Receiver Cost - $

Equation Y: Cost - $ = (Eqn. H) (5833) + 5000

Ash Silo With Steel, Manhole, Fluidizing, and Paddle Mixer Unloader

Equation Z: Cost - $ = (Ash Silo Capacity - Tons) (588) + 4400

where: Ash Silo Capacity = 200–1200 Tons

or

Equation AA: Cost - $ = (Ash Silo Capacity - Tons) (166.67) + 510,000

where: Ash Silo Capacity = 1200–2000 Tons

Control Costs - $

Equation BB: Cost - $ = (Eqn. HM) (10,833) - 30,000

Total System Costs

Cost - $ = Eqn. R + Eqn. U + Eqn. V + Eqn. W + Eqn. X + Eqn. Y + (Eqn. Z or AA) + Eqn. BB

Ash Silos

The ash silos are steel, flat-bottom type and include cone with support steel, manhole, relief valve, fluidizing system, a paddle wheel unloader, an ash floor with steel siding, an enclosure for the ash receiver and stairs, ladders, and platforms. The silos are raised so a truck can drive underneath. The costs are for material only. Items such as tie-ins, foundations, erection, etc., are accounted for in the associated cost factors. The material costs are provided with the ash system costs. (See Equation Z or Equation AA.)

Boiler Water Treatment

Equipment costs for the water treatment systems are based on budget costs and escalated costs. The systems are broken into four categories: (1) zeolite softeners, (2) dealkalizers, (3) demineralizer (cation - decarbonation - anion) units, and (4) mixed bed (cation - anion) units. The costs are a function of cubic feet of resin used or cubic feet for the decarbonator.

The equipment costs include a skid-type unit with valves, controls, interconnecting piping, and regeneration equipment. (For zeolite systems this includes the brine tank.) All installed costs and tie-ins are accounted for in the labor, bulk material, and construction indirect costs. The equipment costs are determined as follows:

Zeolite Softeners

Range 20 to 100 cu ft
Cost = (352) (cu ft of Resin) (2)

Range 200 to 800 cu ft
Cost = (248) (cu ft of Resin) (3)

Dealkalizer

Range 20 to 225 cu ft
Cost = (430) (cu ft)

Range 225 to 700 cu ft
Cost = (400) (cu ft)

Range 700 to 1600 cu ft
Cost = (370) (cu ft)

Demineralizer

Range 20 to 250 cu ft
Cost = ([(1215) (cu ft - Resin)] + 130,000) (2)

Range 250 to 1700 cu ft
Cost = ([(775) (cu ft - Resin)] + 130,000) (3)

Mixed-Bed Unit

Range 10 to 70 cu ft
Cost = [(1620) (cu ft - Resin) + 54,000] (2)

Range 70 to 200 cu ft
Cost = [(1135) (cu ft - Resin) + 54,000] (3)

Mixed-Bed Unit for Condensate Polishing

Range 10 to 70 cu ft
Cost = [(1620) (cu ft - Resin) + 54,000

Range 70 to 200 cu ft
Cost = [(1135) (cu ft - Resin) + 54,000

Chemical Injection Skid

The facility has a single boiler system chemical injection skid. The skid has the equipment necessary to inject chemicals into the boiler drum (phosphates, amines or chelants, and/or antifoaming agents) and an oxygen scavenging chemical (hydrazene or other) into the deaerator. The skid has three 55-gal polyurethane mix tanks with agitators, piping, and valves. Included with the skid are six positive-displacement chemical feed pumps that transfer the chemicals to the boiler drum or the deaerator. The displacement pumps are conceptually sized at 0–10 gallons per hour (gph) and have a discharge pressure of 800 psig. (For higher-pressure units, the drum chemicals would be injected into the feedwater system.)

The skid is sized at 14 ft by 12 ft and has space for all of the previous equipment plus three 55-gal drums of full strength chemical. The installed cost of the skid is estimated as:

- for heating facility—$20,000
- for cogeneration facility—$30,000.

Boiler Water Laboratory

The boiler water laboratory is provided as a means to analyze boiler steam and water for purity. The laboratory includes such items as water sample cabinet with drains; sample coolers (where required); chemical storage compartments; laboratory bench or

table; sink, chemicals, beakers, bottles flasks, exhaust hood, etc. The installed costs are as follows:

- for heating facility—$20,000
- for cogeneration facility—$40,000.

Deaerator

The deaerator is composed of two sections: (1) a deaerating heater and (2) a boiler feedwater storage section. Within the deaerating heater, treated water is deaerated by heating the water to its saturation temperature and scrubbing it with steam to carry away the dissolved gases. The water is then transferred to the storage section by gravity flow. The storage section provides holdup capacity to cover system load swings and emergency situations.

The deaerators are carbon steel spray-tray types. The storage tanks, depending on a user's input, have 5–30 minutes of water storage. The default value is 10 minutes of storage. The deaerators have one-eighth in. corrosion allowance, and come complete with deaerator section, steam nozzle, water trays and sprays, thermometers, storage tank, gauge glass, oxygen test kit, vacuum breaker, relief valve, etc.

The three-boiler facility has a single deaerator sized for three- boiler feedwater flow. The four- and five-boiler facilities have two identically sized deaerators, each sized for 50 percent of the total plant feedwater flow. The costs are estimated as follows:

Cost = (0.0896) (Water Flow - Lb/Hr) + 20,590

Dry Scrubber and Lime System

The dry scrubber is a parallel-flow type unit using lime as a reagent and depositing a dry product at the base and outlet of the scrubber vessel. The unit is designed to treat flue gases from coal-fired boilers to control acid gases (SO_2 and HCl). The acid gas is removed in the form of dry particulate matter so the flue gas will meet U.S. Environmental Protection Agency (EPA) requirements.

The unit atomizes a slurry of slaked lime into fine droplets in the vessel. The reagent contacts the hot flue gases and reacts with the acid gases to form a dry product by evaporation. This dry product is then collected in the bottom of the scrubber and the baghouse. The atomizers can be either rotary or bi-fluid type, designed for easy access and maintainability.

The lime system is an integral part of the dry scrubber system and consists of a lime receiving and handling system, lime day bin, two 100 percent slakers, degritters, lime dilution tank, lime pumps, piping to and from the scrubbers, back flush system, etc. The lime system is sized for total facility PMCR. The foundations and tie-in costs are included as part of the labor, bulk material, and construction indirect costs. Also, the long-term lime silo is estimated separately. The dry scrubber-lime system equipment and installation cost is estimated as a function of flue gas flow, ACFM, into the scrubber. The cost is estimated as follows:

Cost = (2.0) (ACFM) + 240,000

The silo is for long-term storage of the lime for the dry scrubbers. The silo is steel, and includes fill pipe, bin activation system, and a dust vent collection system. The estimated installed costs are:

Range 100–1200 Tons: Cost = (588) (Tons) + 4,400
Range 1200–2000 Tons: Cost = (166.67) (Tons) + 510,000

Baghouses

The budget capital baghouse represents a typical baghouse subcontract. The scope of supply includes:

- baghouse (one per boiler)
- filter bags
- internal inlet and outlet manifolds
- cleaning system
- preheat system for residue hoppers
- maintenance enclosures for fabric filters
- external inlet and outlet flue gas ducts
- control system, programmable logic controller
- insulation and lagging
- ash hoppers (two per module)
- access doors, ladders, stairs, platforms, etc.
- purge air system
- field supervision during erection
- startup services
- freight
- operation manuals
- spare bags.

These costs represent equipment material costs only. Tie-ins, erection, and other associated costs are included with the labor, bulk material, and construction indirect costs. Each baghouse cost is estimated as a function of gas flow. The estimated cost is provided by the following algorithm:

Baghouse Cost - \$ = (5.087) (ACFM) + 230,000

ID Fans

The ID fans draw the boiler flue gas out of the boiler, through such items as the dry scrubber and baghouse, and exhaust the gases into the boiler stack flue. The fan is sized for the combustion gases plus air leakage into the boiler dry scrubber/baghouse system. For the conceptual design, each fan is sized for 100 percent of the flue gas flows plus 15 percent leakage, as well as a static pressure of 20 inches of water.

The costs for foundations, tie-ins, etc., are included as part of the labor, bulk material, and construction indirect costs. The equipment cost is estimated as a function of flue gas flow, ACFM, entering the fan. Cost is provided by two equations:

Range - ACFM 2,000-18,000: Cost = (0.382) (ACFM) + 3,000

Range - ACFM 18,000-110,000: Cost = SQRT [(6935) (ACFM)] + 9000

Pumps

There are four categories of pumps: (1) boiler feedwater pumps (BFWP), (2) plant centrifugal pumps, which include the condensate pumps and the makeup or treated-water pumps, (3) miscellaneous centrifugal sump pumps, which include the rail-track hopper pumps, truck hopper pump, reclaim hopper pumps, neutralization tank pumps, brine wastewater sump pump, and the coal pile runoff pond neutralization pumps, and (4) circulating water pumps. (The chemical feed pumps are addressed under "Chemical Injection Skid" above.)

Boiler Feedwater Pumps

The boiler facility includes two classes of BFWPs: one is a motor-driven multistage centrifugal pump; the other is a steam-turbine-driven multistage centrifugal pump. The estimated costs are a function of pump flow and discharge pressure. The cost includes pump, driver (motor or turbine), valves, starters, governors for turbine drive,

etc. The installation and tie-in costs are included in the labor, bulk material and construction indirect costs. The estimated equipment costs are as follows:

Motor-Driven BFWP

300 psig 10 – 150 GPM Cost = (45.86) (GPM) + 2510

500 psig 30 – 150 GPM Cost = (22.92) (GPM) + 11,750

800 psig 50 – 1200 GPM: Cost = (5.75) (GPM) + 41,500

Turbine-Driven BFWP

300 psig 20 – 150 GPM: Cost = (45.86) (GPM) + 4000

500 psig 30 – 150 GPM: Cost = (22.92) (GPM) + 17,500

800 psig 50 – 1200 GPM: Cost = (85.6) (GPM) + 41,000

Centrifugal Pumps

These pumps move water from various areas of the plant as required to other pieces of plant equipment. The treated-water pumps remove the treated water from the storage tank and deliver the water to the deaerator. The condensate pumps remove condensate from the storage tank and also deliver the water to the deaerator. These pumps are of one- or two-stage design, and the head that they must operate against is largely a matter of piping loss and static-elevation pressure. These pumps are horizontal, end section centrifugal types with constant-speed motors, and come complete with pump, motor, coupling, baseplates and guards. The estimated costs are provided as a function of pump flow. The cost includes pump, motor, coupling, and starter. The installation and tie-in are included in the labor, bulk material, and construction indirect costs. The estimated equipment cost is:

Cost = (7.7) (GPM) 0.94 + 600

Sump Pumps

These pump water from the various plant sumps and include the neutralization sump pumps for the water treatment and pond treatment area. Equipment costs are estimated to be:

100 GPM: Cost = $3500 each

150 GPM: Cost = $3800 each

300 GPM: Cost = $4000 each

Circulating Water Pumps

The circulating water pumps are high-capacity, low-head type pumps. The pumps circulate the cooled cooling tower water through the turbine condenser and plant auxiliary coolers, and then back to the cooling tower for cooling. The facility conceptual design uses three circulating water pumps. Each pump is sized at 40 percent of the maximum circulating water flow rate and for a 30 psi (70 ft) discharge pressure.

The estimated costs are provided as a function of water flow. The cost includes pump, motor, couplings, and starter. The installation and tie-ins are included in the labor, bulk material, and construction indirect costs. The estimated equipment cost is:

$$\text{Cost} = (4.53)\,(\text{GPM}) + 20{,}000$$

Tanks

The facility has many different sizes of tanks, which can be divided into three categories: (1) carbon steel tanks, (2) stainless steel tanks, and (3) fiberglass tanks. The various carbon steel tanks are used for condensate storage, HTHW, condensate return, and blowdown tanks. The stainless steel tanks are used for treated water storage, condensate storage, and condensate return tanks. The fiberglass tank is for the underground fuel oil storage.

Blowdown Tanks

The cost of the continuous blowdown tank is a function of the amount of blowdown entering the boiler and is estimated by:

Cost = (0.05) (Blowdown Flow - lb/hr) + 500

The estimated cost of the intermittent blowdown tank is estimated by:

Cost = (2) (Cost of Continuous Blowdown Tank)

Carbon Steel Tanks

The large carbon steel tanks are dome-roof atmospheric type tanks. These tanks are erected on site on a suitable foundation. The estimated cost includes erection, but the foundation costs are included in the labor, bulk material, and construction indirect costs. The estimated cost is a function of gal of storage, and is provided by:

Range 50,000 – 5 million gal: Cost = (0.179) (gal) + 83,000

The small carbon steel tanks are for water storage, acid storage, caustic storage, etc. These costs are provided by:

Range 2,000 – 36,000 gal: Cost = (0.553) (gal) + 200

Stainless Steel Tanks

The large stainless steel tanks are atmospheric type, sized from 30,000 to 300,000 gal. These tanks include tank saddles and erection. The labor, bulk material and construction indirect costs include the foundations. The estimated cost is a function of gal of storage, and is provided by:

Cost = (0.808) (gal) + 63,400

The small stainless steel tank costs are provided by:

Range 2,000 – 30,000 gal: Cost = (1.45) (gal) + 12,300

Neutralization Tanks

The neutralization tanks are concrete-lined and are estimated, installed, and erected by:

Range 1000 – 36,000 gal: Cost = (0.8974) (gal) + 7,600

Fiberglass Tanks

These tanks are for storage of No. 2 Diesel fuel. The tank is an underground, dual-wall design and includes such items as fill line, vent lines, pump-out line, and leak-detection system. The installation costs are included in the labor, bulk material and construction indirect costs. The tank cost is a function of gal of storage, and is estimated by:

Range 4,000 – 24,000 gal: Cost = (1.417) (gal) + 9,700

Air Compressors

General facility and instrument air compressors are either reciprocating or rotary screw-type units. Each compressor is water cooled and is complete with compressor, motor, guards, intake filters, silencers, oil filter, air receiver, aftercooler,and air dryer. The compressor is conceptually sized in ACFM by the plant size (PMCR). There are two 100 percent air compressors per plant; the estimated cost is a function of the ACFM requirement:

Cost = (101.85) (ACFM) + 5047

Wastewater Treatment

The facility has four types of wastewater that be properly handled and disposed of : (1) sanitary waste, (2) process (boiler system) wastewater, (3) storm water, and (4) coal pile runoff pond discharge.

Sanitary Waste

This comprises all waste collected from water closets, sinks, and potable wastewater such as floor drains in the offices, lunchroom, etc. All waste is collected and discharged to an existing sanitary sewer system. The sanitary system cost includes such items as water closets, urinals, sinks, water heater, drinking fountains, emergency eyewash

stations, floor drains, showers, etc. The cost of the system is estimated as a function of plant size. The system cost is also developed with the labor, bulk material, and construction indirect costs. The sanitary system cost is estimated by:

$$\text{Cost} = (0.1)\,(\text{PMCR}) + 15{,}000$$

Process Wastewater

Process wastewater is generated by the boiler systems. This is mainly wastewater from the treated-water system and equipment cooling water. This water does not contain oil, heavy metals, or other material that would make the wastewater unacceptable for discharge to the sanitary sewer system.

The wastewater from the treated-water system is pretreated in the neutralization tank. This tank neutralizes the wastewater to an acceptable pH value before gradually discharging it to the sanitary sewer system. As an alternative, the water could be discharged to the coal pile runoff pond or possibly be used for ash conditioning. The neutralization tank, piping, and pump costs plus bulk material, labor, and construction contingencies are all included in the costs.

Blowdown Water

Blowdown water is sent to the sewer. The estimated cost of this is included in the blowdown tank and the sanitary system costs.

Other Process Water

Other process water from bearing cooling, facility washdown water, etc., is preliminarily cleaned using dirt-settling chambers or grease/oil traps. This wastewater can then be sent to the sewer, runoff pond, dry scrubber system, or can be used for ash conditioning. The estimated cost of treating this wastewater is included with the other equipment and system costs.

Pond Neutralization

The pond neutralization systems uses programmable controllers for caustic, coagulant, and acid feed rate and pH control. Each system controller also directs the operation of all automatic valves, pumps, mixers, and conveyors associated with the system. The

cost of the pond neutralization system, excluding the pumps, is a function of pond size. The estimated cost of this system is provided by:

Cost = (16.43) (Pond Acres) + 9000

Storm Sewer System

The system includes a storm water collection system that will channel the collected rainwater to an acceptable drainage area. This system will also collect the wash water from the ash and coal area. The drains located in these areas include appropriate traps or settling basins to collect the ash and coal particles. The cost of the storm sewer collection and drainage system is estimated as a function of plant size (acres). (The system does not include a major collection sump.) The estimated cost of this system is provided by:

Cost = (9450) (Plant Acres) + 5200

Piping

The estimated cost is an allowance item for a new facility. Water/steam piping includes all pipe, valves, fittings, hangers, etc., necessary for the boiler/steam system.

For heating facilities, the cost of piping is estimated using one of the following factors:

1. Low Pressure (300 psig or less): Cost = $5/lb of steam
2. Medium Pressure, 650 psig or less: Cost = $6.50/lb of steam

These estimated costs reflect the price difference between the system, e.g., standard weight carbon steel, standard weight and "extra strong" carbon steel with some alloy steel, alloy steel with carbon steel. For cogeneration facilities, the cost of the piping is estimated to be 20 percent more than for the heating facility alone. This cost includes the condenser, additional feedwater heaters, circulating water pipe, etc.

Stack

Facility stacks are freestanding chimneys that enclose steel flues (one flue for each boiler). Depending on the number of boilers, the design has one or two chimneys. The three-boiler facility has a single chimney that houses three individual boiler flues; the four-boiler facility has two chimneys, each housing two boiler flues; the five-boiler

facility has two chimneys, one chimney housing two boiler flues, and the other housing three boiler flues. The steel flues are insulated, have stack sampling ports, and are independently bottom supported.

The chimneys are freestanding, designed for a wind load of 100 mph, and include testing platforms, a safety ladder to the top, interior and exterior lighting, and FAA lights. The cost of the stack includes erection but not the foundation. The foundation cost is included in the labor, bulk material, and construction indirect costs. The erected cost is estimated as:

2-Flue Stack: Cost = (1,456) (Stack Height) + 418,000

3-Flue Stack: Cost = (3,760) (Stack Height) + 200,000

The minimum stack height is 100 ft and the maximum is 325 ft.

Instrumentation

Continuous Emission Monitors

The CEM system provided includes SO_2, NO_x and opacity monitors. Monitoring equipment conforms to applicable federal, state and local codes. The system has a microprocessor-based remote-mounted control unit. The equipment automatically maintains and generates reports as required by local, state, or Federal agencies. The cost of the systems are estimated as follows:

Single Stack - 2 Flues: Cost = $350,000

Dual Stacks - 2 Flues/Stack: Cost = $600,000

Single Stack - 3 Flues: Cost = $400,000

Controls for Heating Facility

Control systems for the heating facility alone are divided into two basic areas: boiler block and yard area. The boiler block includes the controls necessary for the boilers, steam header, and boiler-associated equipment or systems. The boiler block control system is a conventional analog or digital control system linking each boiler for total plant control. Each boiler control is configured for single-loop integrity and has a single control panel for operations overview, with dedicated annunciator windows,

motor control, and status indicators. Also included are auto/manual stations for combustion controls, steam outlet controls and switches, and status indicators for the boiler auxiliaries. Each boiler control is interfaced with the total boiler system control for regulation of feedwater, fuel, airflow, desired boiler output, steam control, and proper combustion.

Boiler auxiliary controls include monitoring and control of heat cycle equipment, boiler feed pumps, feedwater system, condensate system, auxiliary electrical system, etc. The cost of the heating facility controls is estimated as 1 percent of the total boiler cost, or a minimum cost of $200,000.

Controls for Cogeneration Facility

Control systems for the cogeneration facility are divided into two basic areas: boiler block and yard area. The boiler block includes the controls for the boilers, steam header, and boiler-associated equipment or systems. The boiler block control system is a conventional analog or digital control system linking each boiler for total plant control. Each boiler control is configured for single-loop integrity and has a single control panel for operations overview, with dedicated annunciator windows, motor control, and status indicators. Also included are auto/manual stations for combustion controls, steam outlet controls and switches, and status indicators for the boiler auxiliaries. Each boiler control is interfaced with the total boiler system control for regulation of feedwater, fuel, airflow, desired boiler output, steam control, and proper combustion. Boiler auxiliary controls include monitoring and control of heat cycle equipment, boiler feed pumps, feedwater system, condensate system, auxiliary electrical system, etc.

The power or turbine control system includes all controls necessary to interface the boilers and turbine; startup, operate and shut down the turbine; control the turbine-generators auxiliaries; control electrical tie to the utility; etc. The turbine control system uses the same type of control and monitoring equipment as the boiler, plus subpanels for turbine supervisory control, governor control, and turbine water induction protection.

The turbine control system provides for operator control from a central location and complete interlocking for all turbine systems and turbine auxiliaries, including turbine lube oil system, hydraulic system, seals and drains, governor system, and water induction protection system. The governor is compatible with the boiler master control to allow fully integrated unit control. The cost of the cogeneration controls is estimated as 1.5 percent of the cost of the boilers plus the cost of the turbine, or a minimum cost of $350,000.

The yard controls—ash handling, fuel handling, water treatment, etc.—are all basically independent types of systems for their respective processes. The controls typically are programmable, and are included in the cost of the respective systems.

Electrical Facilities Equipment Costs

Diesel Generator

The Diesel generator set provides emergency power to enable safe shutdown of the facility with some power for emergency lights, pumps, controls, etc. The generator set comes complete with Diesel motor (No. 2 fuel oil), generator, automatic start and synchronization, day fuel tank, load following, overload protection, etc. The system is skid-mounted. The cost of tie-ins is included in the installation labor, bulk materials, and construction indirect costs. The equipment cost is estimated to be a function of kilowatt (kW) output.

$$\text{Cost} = (182.5)\,(\text{kW}) - 39{,}700$$

Substation for Heating Facility

The heating facility requires an electrical substation to receive power from the grid. The cost is estimated as an allowance type of cost. The substation steps the incoming voltage down from 13.8 kV to 480 volt bus system. It is a double-ended substation that includes two main stepdown transformers with oil-filled breakers and other necessary equipment, hardware, wire, etc. The cost of the tie-ins is included in the labor, bulk materials, and construction indirect costs. The equipment allowance cost is estimated to be a function of plant size, and is estimated as follows:

$$\text{Cost} = (0.3625)\,(\text{PMCR}) + 240{,}000$$

Substation for Cogeneration Facility

The substation for the cogeneration facility includes a 13.8 kV system generating to the grid. Most of this system's cost is included with the turbine-generator cost. An allowance is added to cover grid protection and tie-in costs. This is estimated to be a lump sum of $30,000. Therefore, the estimated cost of the cogeneration substation is as follows:

$$\text{Cost} = (0.1875)\,(\text{PMCR}) + 530{,}000$$

General Facility

This represents the electrical equipment necessary for the facility. Necesseties include breakers for equipment and the facility, wiring, lights, cable trays, conduits, etc. The estimated cost of this is 6 percent of the facility's equipment, structures, and controls.

Site Work

Site Development

The site development cost includes work necessary to prepare a site for construction. This work includes such activities as, site grubbing and clearing (elimination of trees, bushes, etc.); some preliminary ground investigation (core drilling, site history investigation, etc.); some site leveling; control of site drainage; mobilization; etc. Since this work is highly site-specific, the program provides only a very rough estimate of this cost. The cost estimate is provided as a function of total site (plant plus fuel pile plus runoff pond) acres. Cost is estimated as $2500 per acre.

Fuel Storage Area

Coal pile storage area development cost represents the work necessary to prepare the site for construction, removal of the overburden, installing an impermeable layer for under the storage pile, and installing a storage drainage system that discharges to the pond. The estimated cost is $22,000 per acre, or $0.50 sq ft.

Site Improvements

This category is an allowance type of item provided for such things as site landscaping, architectural improvements, sidewalks, parking lots, fences, etc. The cost of this allowance is estimated as a function of plant size, and is provided by:

$$\text{Cost} = (0.5)\,(\text{PMCR}) + 100{,}000$$

Building and Services

Building

The building is the structure that houses the boilers, feedwater treatment, turbine-generator (for cogeneration facilities), plant offices, maintenance, locker rooms, etc.

This building is a stand-alone structure with insulated metal siding, windows, roof vents, sidewall louvered vents, etc. The building includes concrete slab on grade and other upper floor areas (with most upper floors being grating). The building comes complete with floors, stairs, platforms, windows, vents, handrails, etc. The rough cost of the building is provided as a function of the number of cubic feet of building area. The cost is estimated as $4.75 per cubic foot (cu ft) of building area.

Elevator

The facility includes one freight/personnel elevator. The elevator is 6 ft by 8 ft internal, and will operate from the first floor elevation to the top of the boiler house. The elevator is a traction type with automatic functions. The cost of the elevator depends on the height (rise) and the number of stops. Cost is estimated as follows:

40 ft Rise with two Stops: Cost = $100,000

70 ft Rise with three Stops: Cost = $150,000

120 ft Rise with five Stops: Cost = $225,000

Communications

This system includes telephone stations, attendant console, PABX, amplifiers, battery, battery charger, paging speakers and horns, wiring systems, and all conduit necessary. Units installed in high-noise areas such as the boiler floor are provided with acoustic booths and noise-limiting devices on the telephone receiver. Other features included with the system are direct station-to-station calls within PABX without attendant assistance, direct outward dialing for outside and long-distance calls, direct access to paging system and night answering, and call forwarding. The system cost is an allowance item based on plant size:

Cost = (0.111) (PMCR) - 500

where: Minimum Cost = $5,000

Fire Protection

The facility's fire protection system is basically a wet pipe system. The system includes a separate firehouse; two 1500 gpm, 125 psig Diesel-driven fire water pumps,

each with an 8-hour Diesel storage tank, a jockey pump, firehouse, fire water storage tank, and fire department connections. Other important features are:

- an outside-plant loop distribution system with fire hydrants
- individual water loop systems, fed from the plant loop system, to service boiler house, coal-handling system, baghouse, personnel areas, and turbine-generator area
- an inert-gas (halogen-based) system for the plant electrical room to suppress fires by oxygen scavenging.

Also included in the cost are such items as alarms and water gongs, portable fire extinguishers, fire hose cabinets, water monitors, sprinkler heads, etc. The cost allowance for fire protection is estimated as 3 percent of the facility's equipment, structures, and controls.

Furniture

Furniture is required in a new facility for plant offices, lunchroom, locker rooms, maintenance shop area, etc. The furniture included in the conceptual design includes desks, swivel chairs, two- and four-drawer file cabinets, bookcases, side chairs, stacking chairs, lunchroom tables, benches and cabinets with counter tops, lockers, locker room benches, supervisor floor desks, metal storage bins, racks, etc. Furniture is an allowance item for the new facility. Cost is based on PMCR:

$$\text{Cost} = (0.2875)\ (\text{PMCR})$$

Heating, Ventilation, and Air Conditioning

The HVAC system design serves the facility's offices, lunchroom, locker rooms, and electrical equipment room. The remainder of the facility is not air conditioned. The air conditioner is complete with cooling coils, fans, ductwork, insulation, controls, etc. Cost of air conditioning, including installation, is estimated as follows:

$$\text{Cost} = (0.405)\ (\text{PMCR}/1000) + 1013.5$$

For heating of the facility, the design includes steam or hot water heating coils for general facility heating. The coils are installed with air makeup units in the plant, radiators in offices, lunchroom, locker room, and above doors, below windows, etc. The cost of the heating system is an allowance item based on the size of the facility. The cost of the heating coils (makeup air units) is estimated as:

Cost = (0.5375) (PMCR) + 8000

Mobile Equipment, Spare Parts, and Tools

Mobile Equipment

The mobile equipment is described in Chapter 4 under "Facility Auxiliary Equipment—Mobile Equipment." The cost of the various equipment is provided as an allowance cost per unit. All self-propelled equipment listed below is Diesel-powered:

- Front-end loader: Cost = $210,000 each
- Light-duty front-end loader: Cost = $75,000 each
- Forklift: Cost = $20,000 each
- Dump (5-ton) truck: Cost = $25,000 each
- Pickup (three-quarter-ton) truck: Cost = $14,000 each
- Power sweeper: Cost = $5000 each
- Drop box (40 cu yd): Cost = $8000 each

Spare Parts

The costs of spare parts for major equipment and systems are an allocation cost, and estimated as a function of plant size and equipment costs:

Cost = [2.62 - (0.0022) (PMCR) / 1000] (Facility equipment, structures, and controls) / 100

where: (Facility equipment, structures, and controls) includes all costs specified in this chapter.

Facility Consumables—Initial Inventory

A new facility must start with an initial inventory of consumables. These items are normally considered yearly operational needs, but a new facility must have an initial inventory to begin operations. Items included in this category are packing seals, grease, oil, small parts (bearings, valves, pipe, fittings, etc.), rags, light bulbs, buckets, mops, cleaning agents, towels, etc. The estimated cost is provided by the following factor:

Cost = (0.35) (Spare Parts Cost)

Tools

A new facility basically needs two types of tools: (1) hand tools and (2) major tool room equipment, as discussed in Chapter 4. These costs are an allocation cost and estimated as a function of plant size. The estimated allowance or cost is:

Cost = (0.4375) (PMCR) + 106,000

Condenser

The condenser for cogeneration facilities is a two-pass, shell and tube surface type sized for full turbine throttle flow condensing at 2.5 in. HgA or 3 in. HgA, depending on the steam turbine system. The equipment costs are determined as follows:

Cost = (1.10) (PMCR) + 12,000

Items for tie-ins, foundations, and erection are incorporated in the installation costs.

Cooling Tower

The cooling tower for cogeneration facilities is discussed in detail in Chapter 4 under "New Cogeneration Facility—Cooling Tower."

The foundation, concrete basin, and tie-in costs are included as part of the labor, bulk material, and construction indirect costs. The cooling tower cost, equipment, and erection is a function of water circulation rate, and is estimated by the following:

Cost = (35.5) (Circ. Rate - GPM) - 42,000

Feedwater Heaters

The feedwater heaters are used in the regenerative feedwater heating cycle to heat the feedwater before it enters the boilers. The feedwater heaters are a closed shell-and-tube design and include:

- heat exchanger with integral drain cooler
- shell safety valve
- channel relief valve

- channel vent
- emergency drain
- controls and gauge glass
- drain nozzle.

The cost of the feedwater heaters is a function of operating pressure and square feet of tube surface, tube surface being a function of feedwater flow and design temperature rise. The estimated heater costs are as follows:

50 psig or less: Cost = (10) (Sq ft of Surface Area) + 5000

50 to 175 psig: Cost = (9.33) (Sq ft of Surface Area) + 6700

175 to 500 psig: Cost = (14.3) (Sq ft of Surface Area) + 8000

Turbine/Generator

The cogeneration facility conceptual design uses a single extraction-condensing turbine/generator to generate electricity and provide the plant, heating system, and process steam requirements. The 600 psi, 750 °F design steam turbine has a maximum of two steam extractions: (1) 170 psig, which is used for the heating system, possibly a feedwater heater, and/or process steam, and (2) a 35–50 psig extraction for feedwater heating. Total allowable steam extraction is maximized at 80 percent of the full-turbine throttle flow steam rate. (PMCR for the conceptual design means full-turbine throttle flow.) This allows a minimum of 20 percent flowing to the turbine exhaust (i.e., condensing). This minimum steam is necessary to keep the exhaust stages of the turbine cool. The turbine is conceptually designed for full flow condensing. The 600 psi, 750 °F turbine steam condition uses two types of turbines: (1) a skid-mounted, gear-driven type for lower flows, and (2) a direct-drive type for higher flows. The equipment list for the turbine-generator is presented in Chapter 4 under “Turbine-Generator.”

Installation of the turbine-generator is included as labor, bulk material and construction indirect costs. The estimated costs are a function of full throttle flow, pressure and temperature; condensing flow and pressure; number of extractions; maximum extraction flows and extraction pressures. The cost estimate for the turbine-generator is as follows:

- 600 psig, 750 °F gear-driven turbine
  Range 50,000 – 100,000 lb/hr Throttle Flow

Cost = [(47.5) (PMCR) - 1.85] Million

- 600 psig, 750 °F direct-drive turbine
  Range 100,000 – 600,000 lb/hr Throttle Flow
  Cost = [(5.867) (PMCR) + 2.76] Million

Steam Distribution System

Steam distribution system design depends on the type of system and the distance the system must extend. The model allows the user to select from four types of designs:

1. tunnel construction
2. direct burial ricwil*-type casing
3. shallow trench/walkway construction
4. above ground single stanchion construction.

These designs are illustrated in Figures 12–15.

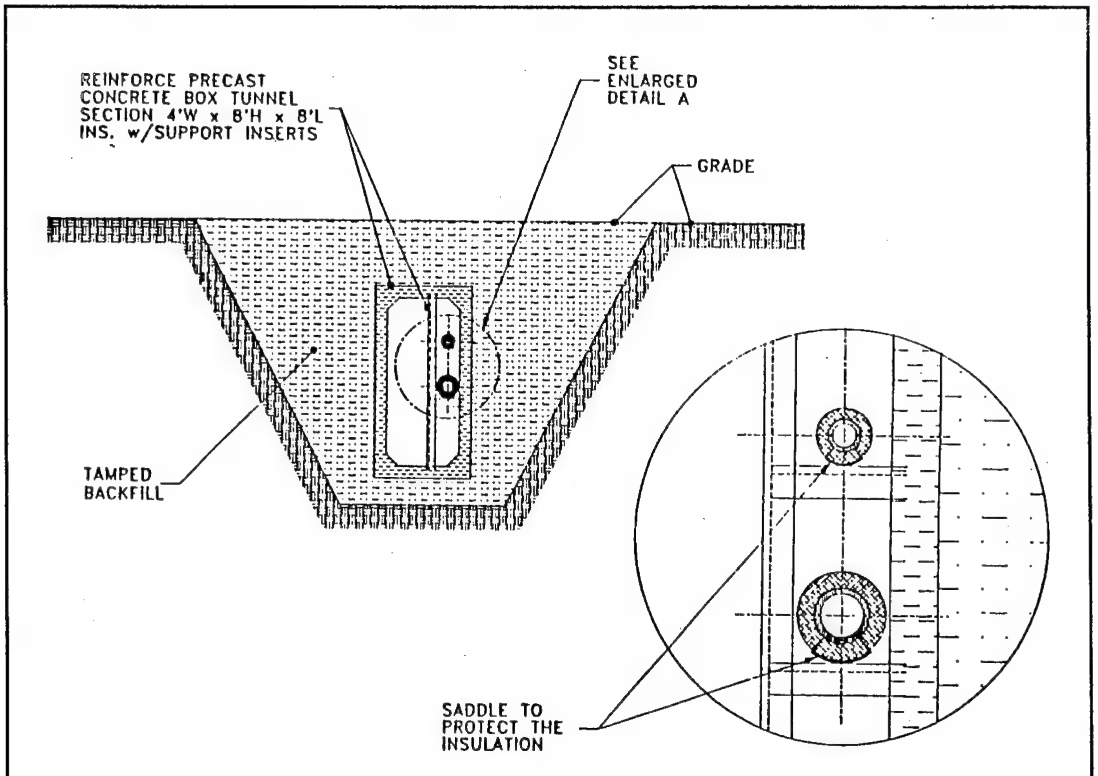


Figure 12. Steam distribution system design using tunnel construction.

* The term "ricwil" is a generic industry term for a type of heat distribution manufactured by RicWil, Inc., 10100 Brecksville Rd., Brecksville, OH, 44141-8051.

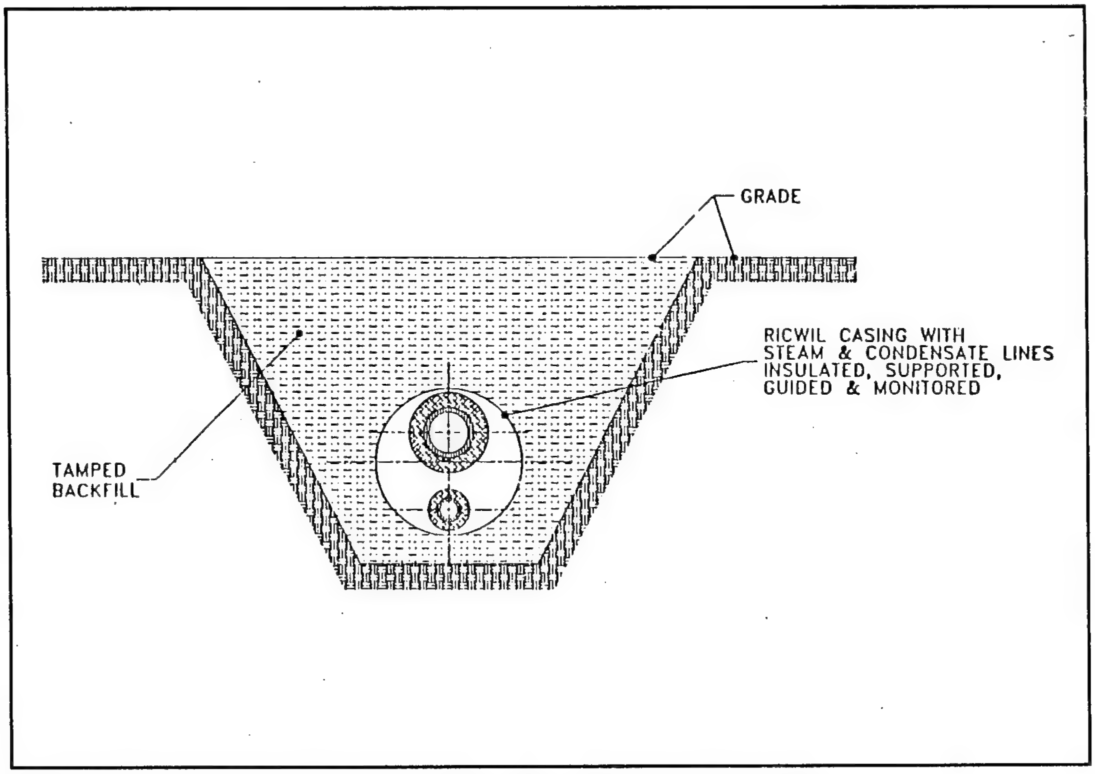


Figure 13. Steam distribution system design using direct burial ricwil casing

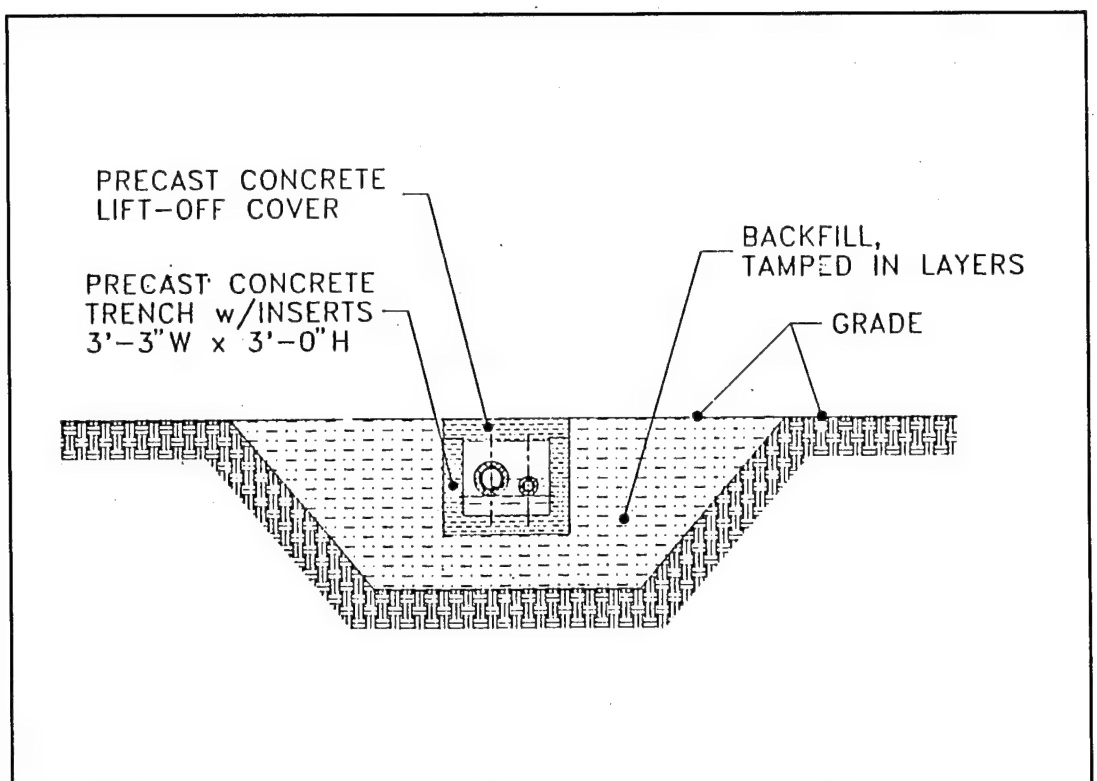


Figure 14. Steam distribution system design using shallow trench/walkway construction.

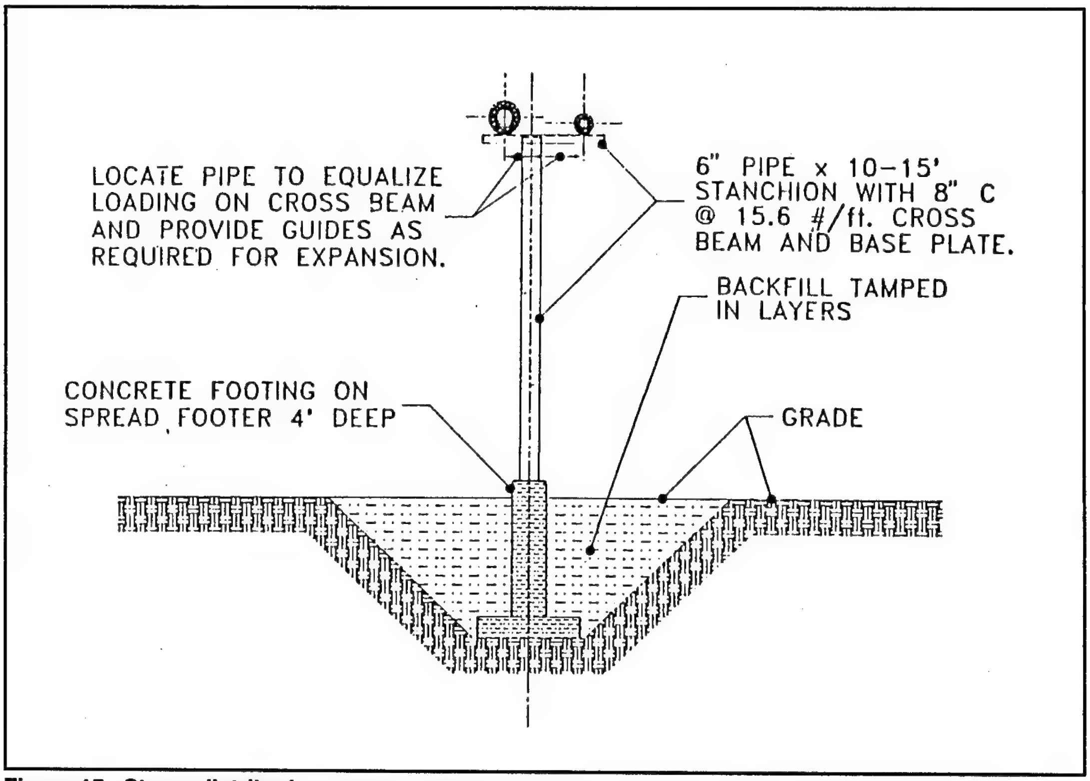


Figure 15. Steam distribution system design using aboveground single-stanchion construction.

After the computer model user selects the system or systems to be utilized, he or she must input the length of each system and the number of branch lines or connections. The software uses this information to provide a budget estimate of the installed constructed cost of the steam distribution system. The budgetary installed cost of the various steam distribution systems are estimated by the following:

Cost = [[$/ft]/ft of Tunnel] [1+ ((% Mat'l. Escalation) + (% Labor Escalation)/200)] [Labor Productivity Factor] [Labor Cost - $/Hr/$20.00]

where: $/ft =
Tunnel construction = $700/ft
Direct burial ricwil construction = $270/ft
Shallow trench/walkway construction = $250/ft
Aboveground single stanchion = $275/ft

Branch Connections:

Cost = [Number of Connections] [Cost/Connection] [1+ ((% Mat'l. Escalation) + (% Labor Escalation)/200)] [Labor Productivity Factor] [Labor Cost - $/Hr/$20.00]

where: The 1988 estimated fourth quarter cost of Ohio construction* is:
Tunnel: $1500/connection
Direct burial: $1000/connection
Trench: $ 600/connection
Overhead: $ 750/connection
(Prices include an estimate for valves, tie-ins, and construction costs)

Freight Costs

This category is to cover the cost of freighting materials to the project site. The cost of this is estimated as a percent of equipment cost.

The estimated cost of this typically ranges from 1.5 to 4.5 percent for areas of the continental United States. The value used is 2 percent of the total facility costs.

The freight costs for bulk materials are included as part of bulk materials costs.

Installation Costs

The installation costs are derived by multiplying the equipment costs by a series of factors. These factors are used to identify the direct labor man-hours and the bulk material costs. Actual labor costs are derived by multiplying a wage rate by the number of direct labor man-hours. The construction indirect costs are derived by taking a percentage of the direct labor costs.

Direct Labor Man-hours

Direct labor man-hours are the total craft man-hours required to build the plant. These include skilled workers such as pipefitters, boilermakers, electricians, insulators, painters, laborers, steelworkers, masons, and foremen. These factors, when multiplied by the equipment costs, yield the total direct labor man-hours associated with the installation of that equipment. They account for the labor man-hours for any foundations, structural steel, buildings, piping, electrical, instrumentation, painting, or insulation required to completely install that particular piece of equipment.

* Ohio construction costs are used as the baseline factor of 1 in CHPECON costing models.

After the labor man-hours are derived, they are multiplied by a productivity adjustment. Using a 1.0 factor for labor productivity will result in direct labor man-hours for union construction in Ohio. Table 10 shows the factors for all other states.

As an example, assume that a New Jersey plant site was chosen. The model would multiply the labor man-hours by 0.97, reducing the total man-hours required to complete the installation. This man-hour reduction is due to statistics showing that New Jersey construction crews are more productive than Ohio crews. Conversely, multipliers greater than 1.0 increase total man-hours, indicating construction crews that are less productive than Ohio crews.

Direct Labor Costs

Direct labor costs are derived by multiplying the labor man-hours by the average base wage rate for the plant site being considered. The base wage is that which excludes all payroll benefits and burdens. In the model, the average base wage rate for the proposed plant location is represented by the pipefitters union base wage. The pipefitters base wage for each state is an average of the pipefitters union base wage rates for the major cities in that particular state. The program can estimate labor costs for other plant locations and for open-shop construction if the labor productivity and base wages are known.

Bulk Materials

Bulk materials are any permanent material required for the plant, other than the equipment. These include concrete, pipe, wire, conduit, structural steel, etc. The factors from Table 11, when multiplied by the equipment costs, yield the total bulk material costs associated with the installation of that equipment. These materials account for any foundations, structural steel, buildings, piping, electrical, instrumentation, painting, or insulation which are required to completely install that particular piece of equipment.

Indirect Costs

Construction indirect costs are for field indirect costs, construction services, field staff, payroll benefits and burdens for direct and indirect labor, small tools and consumables, and the construction equipment. The field indirect costs include all temporary facilities, such as service buildings and office trailers, temporary roads, parking, and material laydown areas. Construction services include job cleanup, medical supplies,

Table 10. Productivity factors by state.

State	Productivity Multiplier	Average Wage
AK	0.87	27.00
AL	1.00	13.00
AR	1.00	8.00
AZ	1.00	17.85
CA	1.00	23.00
CO	1.00	12.00
CT	0.98	18.22
DE	1.00	18.05
FL	1.00	10.00
GA	1.00	10.00
IA	1.00	14.77
ID	1.00	17.63
IL	1.21	18.05
IN	0.98	18.17
KS	1.00	11.55
KY	1.13	10.00
LA	1.00	11.97
MA	0.87	18.09
MD	1.00	12.94
ME	0.87	14.35
MI	1.00	16.00
MN	1.00	17.50
MO	1.00	18.00
MS	1.00	9.00
MT	1.00	14.51
NC	1.00	6.75
ND	1.00	9.95
NE	1.00	12.91
NH	0.87	16.00
NJ	0.97	18.44
NM	1.00	11.30
NV	1.00	19.59
NY	1.00	18.50
OH	1.00	18.60
OK	1.00	9.81
OR	1.00	18.31
PA	0.98	17.08
RI	0.87	19.07
SC	1.00	4.45
SD	1.00	6.00
TN	1.00	10.00
TX	1.00	9.50
VA	0.87	14.61
VT	0.87	14.70
WA	1.00	18.00
WI	1.00	16.00
WV	0.93	16.97
WY	1.00	12.00
UT	1.00	14.41
HI	1.00	20.00

construction equipment handling and maintenance, field office supplies, and telephone.

Field staff covers the salaries and subsistence for contractor field staff. Subsistence includes meals, lodging, travel expenses, etc. Also included is site security, medical, warehouse, and clerical personnel. The payroll benefits include vacation, holidays, sick time, and medical insurance. The burdens include social security, and Federal and state unemployment insurance.

Table 11. Labor hours and bulk material cost factors.

	Labor, hr/$ Capital	Bulk Factor
Boilers		
PC Boilers	0.0013	0.12
Airheaters	0.008	0.05
Desuperheater	0.0161	0.18
Coal Handling	0.0065	0.15
Fuel Handling		
Long Term Storage Tanks	0.0242	0.22
Short Term Storage Tanks	0.01	0.16
Ash Handling	0.243	0.45
Dry Scrubber & Lime System		
Dry Scrubber & Lime System	0.0215	0.4
Lime Silo	0.0161	0.18
Baghouse & ID Fan		
Baghouse	0.01344	0.28
ID Fan	0.018	0.18
Boiler Water Treatment		
Zeolite Softeners	0.0091	0.3
Dealkalizer	0.015	0.3
Demineralizer	0.015	0.3
Mixed Bed	0.0188	0.35
Condensate Polisher	0.0188	0.35
Chemical Injection	0.0081	0.15
Boiler Water Laboratory	0.0054	0.2
Deaerator	0.0188	0.28
Tanks		
Condensate Storage	0.0242	0.22
Treated Water Storage	0.0242	0.22
Acid & Caustic Tanks	0.01	0.16
Blowdown Tank - Cont.	0.0118	0.28
Blowdown Tank - Inter.	0.0172	0.28
HTHW Expansion Tank	0.0242	0.22
Condensate Return Tank	0.0242	0.22
Facility Fuel Oil Tank	0.0134	0.12
Neutralization Tanks	0.0269	0.05

	Labor, hr/$ Capital	Bulk Factor
Pumps		
Motor Driven BFWP	0.0172	0.18
Turbine Driven BFWP	0.0177	0.22
Centrifugal Pumps	0.0118	0.3
Circulating Water Pumps	0.0118	0.16
Sump Pumps	0.008	0.12
Air Compressors	0.0081	0.35
Wastewater Treatment		
Sanitary System	0.035	0.28
Neutralization Pond	0.0376	0.05
Storm Sewer System	0.0323	0.12
Piping		
Stack	0.0322	0.08
Piping	0.035	0.5
Instrumentation		
Continuous Emission Monitors	0.0065	0.5
Controls	0.0242	0.4
Electrical		
Diesel Generator	0.0054	0.3
Substations	0.0242	0.33
General	0.0242	0.18
Building & Services		
Building	0.000323	0.2
Communications	0	0.25
Fire Protection	0.0188	0.12
Furniture	0.006	0.05
HVAC	0.0323	0.12
Elevator	0.0188	0.15
Site Development	0	0
Spare parts, tools, mobile equipment		
Mobile Equipment	0	0
Facility Consumables	0	0
Tools	0	0
Spare Parts	0	0
Condenser	0.0065	0.15
Cooling Tower	0.0081	0.35
Feed Water Heater	0.0215	0.12
Turbine Generator	0.0188	0.35

The program uses a factor of 75 percent of the direct labor dollars to account for construction indirect costs. This factor is based on data from a number of similar projects using union construction crews. This percentage will probably increase for open-shop

scenarios because, as labor costs decrease as in the case of open-shop construction, the percentage for construction indirect costs tends to increase.

Permit Development

This section estimates the cost to develop, apply for, and obtain the necessary EPA, state, and local permits to begin construction. The permit development cost estimate is provided as a function of plant size, as follows:

$$\text{Cost} = (2.222)\,(\text{PMCR}) + 390{,}000$$

Engineering Costs

This section represents the contract engineering required to design the plant. The cost includes design engineering as well as the engineer's fee. It accounts for the cost of preparing the specifications, drawings, soliciting bids for equipment, and preparing bid evaluations. It covers all engineer salaries and the overheads, such as reproduction, computer services, travel, final drawings, field changes, etc. The estimated cost of these services is 12 percent of total facility cost.

Construction Management Costs

This section represents the contract management needed to build or construct a facility. Construction management is responsible for managing the construction, obtaining the construction bond, site security, insurance, etc. These services are estimated as 7 percent of the total facility cost.

Construction Contingencies

The contingency is intended to cover inaccuracies associated with the estimating approach and to cover any items that must be performed to complete the project as originally defined. This cost is not intended to cover scope changes. The contingency is estimated as 15 percent of the total cost of the facility through construction.

Owner's Management

This section is to cover the owner's cost of building a project. This includes payment of the main contractor, quality assurance for the project, schedule management, etc. The estimated cost is 6 percent of the total cost.

Startup Costs

This section is to cover the cost of initially starting up and troubleshooting the equipment and systems for integrated operation. The category also includes such items as startup fuel, line and system cleaning, boiler cleaning and blows, turbine starts, purchase power, etc. This estimated cost is provided as a function of plant size, and is estimated by:

$$\text{Cost} = (0.833)\,(\text{PMCR}) + 133{,}000$$

6 Facility Operations and Maintenance Cost

This section of the model was developed to provide budgetary operations and maintenance (O&M) cost estimates for new PC-fueled steam production and cogeneration power plants. These estimated costs are divided into two parts: operational cost and major maintenance cost. The operational cost components include day-to-day costs of operating and maintaining the facility. Costs for major equipment rebuilds (e.g., turbine rebuilds, baghouse rebagging, major boiler outages, boiler feedwater pump rebuilds, water-treating resin replacement, etc.), are included in the major maintenance cost. After calculating each cost, the program sums the costs to estimate the total annual costs for each year of operation. The costs provided by the cost algorithms are based on fourth quarter 1988 dollars, and escalated yearly for the development of future costs.* The O&M costs are then used with the capital costs to determine the total life-cycle cost of the conceptual new facility being evaluated.

Operational Costs Components

The cost components included in this category estimate the day-to-day costs of operating and maintaining a steam or cogeneration facility. The costs included in this category are discussed below.

Labor

The labor category is divided into four classifications: (1) management, (2) operations and maintenance, (3) yard or fuel storage, and (4) steam system.

Management includes the personnel required to manage and direct all operations of the facility. Included in this category are the plant manager, assistant plant manager, plant engineers, plant secretary, clerks, janitor and instrumentation technician positions. Their duties include the overall operations, maintenance, and planning of the facility; payroll and accounting functions; receptionist and secretarial responsibilities; maintenance parts inventory control, restocking, and ordering for major maintenance; cost control, etc.

* For specific details, see Lin et al. 1995, ch 7, "Life Cycle Cost Economic Analysis."

Operations includes the personnel required to operate the facility. Included in this category are the shift supervisor, operators, assistant operators, and laborers. These positions are also responsible for minor maintenance and some preventive maintenance—painting, seal repacking, greasing, oiling, etc.—when not required to maintain the plant's operation.

Fuel storage personnel are responsible for operation of the long-term fuel storage area. This includes fuel stocking, reclaim, and unloading operations.

Maintenance includes the personnel required to perform plant maintenance. Included are the mechanical and electrical maintenance positions, and laborers. These positions are mainly responsible for plant maintenance: rebuilding or replacing pumps, small fans, soot-blower repairs, nominal boiler repairs, air compressors, instrumentation, plant electrical system maintenance, etc. When required, these personnel are also responsible to assist in plant operations, e.g., coal unloading and handling, ash handling, etc. Steam system labor includes the personnel required to maintain the steam distribution system.

Table 12 indicates the default values and wages for each type of labor. The estimated cost of labor was developed as a function of plant size, number of boilers, whether the facility is a heating or cogeneration facility, fuel type, personnel salary, and productivity level. The user can specify the salary level, percent fringe benefit multiplier, and percent overtime for each type of personnel. The program will then compute the salary cost in dollars per year.

Fuel

This category is broken into two components; (1) primary and (2) secondary fuel. Primary fuel is the fuel used to produce the steam for heat. Secondary fuel is the fuel used for starting the boilers, car thawing for coal receiving, plant vehicles, Diesel generators, etc. Primary fuel cost is calculated by multiplying the amount of fuel used annually by the cost of the fuel.

Heating facility primary fuel use is estimated by using the average steam load per month divided by the maximum steam load times the fuel utilization rate at the maximum steam flow. The fuel consumption rate (lb/hr) is then multiplied by 24 hr/day and the number of days per month for the monthly fuel rate. To calculate the annual fuel cost in 1988 dollars, sum the monthly fuel rates and multiply by the fuel cost. For future costs, the 1988 cost is increased by the escalation rate.

Table 12. Default labor categories and wages.

Labor Category	Salary ($/hour)	Overtime
Plant Manager	26.50	No
Plant Engineer	22.00	No
Plant Technician	16.50	No
Plant Clerk	12.00	No
Plant Secretary	10.50	No
Plant Janitor	8.25	No
Shift Supervisor	17.00	Yes
Operator	12.00	Yes
Assistant Operator	10.00	Yes
Laborer	8.50	Yes
Fuel Equipment Operator	10.00	Yes
Assistant Fuel Equipment Operator	9.00	Yes
Fuel Equipment Laborer	8.50	Yes
Maintenance Mechanic	13.00	Yes
Electrical Maintenance	13.00	Yes
Maintenance Laborer	8.50	Yes
Notes: Overtime is equal to 15 percent of base salary. Fringe benefits are equal to 42 percent of base salary.		

Cogeneration facility primary fuel use is estimated by using the fuel utilization rate (lb/hr) at PMCR, then multiplying by 24 hr/day times 365 days/year times 0.85 (the power production factor developed from partial and total load loss due to boiler and turbine outages planned and forced). Secondary fuel use rate is estimated by the following:

Car Thawing: Gallons No. 2 Diesel Per Year = [(0.1) (PMCR)+21,000]

No. Car Thawing: Gallons No. 2 Diesel Per Year = [(0.004(PMCR)+16,000]

The cost of the secondary fuel, in 1988 dollars, is determined by multiplying the fuel use (gallons) times the fuel cost. For future costs, the 1988 costs are increased by the escalation rate.

Lime

The cost of this component is calculated similar to the primary fuel cost. The lime monthly use rate is calculated for each month of the year; the yearly use is determined

by summing the monthly rates. The cost (1988 dollars) is then determined by multiplying lime use times cost per quantity.

Water

The water cost estimate is determined by the amount of water consumed by the facility, multiplied by the cost of water. The amount of water consumed is estimated by the following system uses.

- Condensate makeup water use:

  Condensate makeup = (average monthly steam flow) (user input) (1 - % condensate return/100) (24 hr/day) (no. of days/month)

- Blowdown makeup is determined similarly to condensate makeup using the percent blowdown input by the uses:

  No. of gallons per month = [(no. of gal/min @PMCR) (monthly average steam rate)] / [(PMCR) (24 hr/day) (no. of days/month)]

- Plant water use includes ash conditioning and facility washdown. Ash conditioning is estimated as 10 to 40 percent by weight of the ash generated.

  Estimated monthly ash flow = [(ash produced) (average monthly steam flow)] / [PMCR (24hr/day) (no. of days/month)]

  Calculated ash conditioning = [(est.monthly ash flow) (user selected %water in ash)] / 100

  Parameters:

  — Convert the amount of water to gallons
  — The user-selected %water default value is 10.

- Facility washdown and miscellaneous water use is estimated as follows.

  Estimated use = 780,000 gal/yr = (25 gal/min) (60 min/hr) (3 hr/day) (7 day/wk) (52 wk/yr)

- Personnel water use is estimated as 8750 gallons per year per employee.

- Cooling tower use is estimated by the following:

  Estimated use = (circulating cooling water makeup) (60 min/hr) (24 hr/day) (365 day/yr) (0.77)

- The water treatment wastewater estimate depends on the type of water treatment system:

  Zeolite system wastewater estimated use = (wastewater/regeneration}gal)(no. of regenerations/yr)

  Demineralizer system wastewater estimated use = (Cation & Anion Vessels Backwash Water + Cation & Anion Rinse Water) (no. of regenerations/yr)

  Mixed-bed system wastewater estimated use = (Mixed Bed Vessel Backwash + Mixed Bed Rinse Water) (no. of regenerations/yr)

  Condensate polisher system wastewater estimated use = (Mixed Bed Vessel Backwash + Mixed Bed Rinse Water) (no. of regenerations/yr)

Number of regenerations per year is estimated by:

[(Condensate Makeup/Yr + Blowdown Makeup/Yr) (0.15) (no. of Trains)] / [(Treated Water Flow/Train) 1440].

Number of trains is determined by the continuous treated water flow rate, where from 0–600 gpm, the system comprises two trains and from 600–1200 gpm, the system comprises three trains.

Sanitary Sewer

The estimated cost of the sanitary sewer is a direct function of the amount of waste sent to the sewer. The sewer flow is estimated by the following:

Estimated cost = [0.5 (blowdown water makeup) + (facility washdown and miscellaneous water) + (personnel water use) + (cooling tower blowdown)] (sewer cost)

Note: the water rate estimate must be in the same units as the sewer cost rate. If cost is given in dollars per gpm, then water rate must be given in gpm.

Ash Disposal

The estimated cost of ash disposal is a direct function of the amount or weight of waste (ash or residue plus moisture content) produced by the facility. The amount of waste per month is estimated by the following:

> Estimated waste = [(mass of waste/hr) (24 hours per day) (average monthly steam load) / PMCR] [no. of days/month (1 + %water added for ash conditioning / 100)]
>
> Note: the amount of yearly waste must be in the same units as the cost of waste disposal. If the cost is given in dollars per ton, then the amount must be given in tons.

Summing each monthly waste generation provides an estimate of the amount of waste generated per year. Multiplying this by the cost of waste disposal provides the estimated cost of waste disposal at the location of the disposal site. In CHPECON, the cost of waste disposal includes freight costs.

Electricity Consumption

The cost of electricity is divided into three categories: process use, general facility use and utility equipment and standby charges.

Process charge is the cost of the electricity to operate the facility steam/power generation system. This cost is determined monthly; then monthly costs are summed for the yearly estimated cost. Each monthly charge is estimated by the following:

> Estimated process charge = (total system motor - kW/hr) (24hr/day) (no. of days/month) (month's average steam load) / PMCR (electricity cost)
>
> Note: the system motor kiloWatt total includes such users as pump motors, fan motors, conveyor systems, etc.

Summing the monthly costs provides the yearly process electrical load costs.

The general facility electricity cost is estimated mainly as the facility lighting load. This is divided into the plant or building, and the facility area lighting. The plant and facility lighting yearly costs are estimated as follows.

Est. plant yearly cost = [0.10] [building size - cu ft] [24 hr/day] [365 days/year] [Electricity Cost - $/kWhr] / [1000]

Est. facility yearly cost = [(Plant Acres) + (Long-Term Coal Storage Acres)] (43,560 sq ft/Acre) [(0.067 W/hr/hr.ft^2)/1000 W/kW)] (12 hrs/Day) (365 Days/yr) (Electricity Cost}$/Kwhr)

Utility equipment and standby charges are the cost of renting the facility substation, power lines into the facility, and a standby demand charge. These costs usually apply only to cogeneration facilities and depend totally on the location of the facility. The user must input these costs where applicable. The total facility electrical yearly cost is then estimated by summing the process use yearly cost, general facility use yearly costs and utility equipment and standby charges yearly costs.

Facility Chemicals

Facility chemical usage is divided into three main areas: (1) boiler, (2) water treating, and (3) cooling tower. All three are dependent on facility steam load. Boiler chemical usage is dependent on boiler water quality and blowdown rate. Usually, the higher the water quality and/or blowdown rate, the lower the amount of boiler chemicals required. For the design estimate, all boilers will use a coordinated phosphate treatment—a mixture of 60 percent trisodium phosphate (by weight) and 40 percent disodium phosphate (by weight). The boiler drum water is to conceptually have an ion concentration of 10 ppm (PO_4---). The chemical monthly usage is estimated by the following:

A. Lb - 100 percent PO_4/Hr = (Average Steam Flow Rate/Month/Hr) (% Blowdown) / (1 x 105)

B. Lb Trisodium Phosphate/Hr = (0.6) (A) / (0.58)

C. Lb Disodium Phosphate/Hr = (0.4) (A) / (0.67)

D. Lb Trisodium Phosphate/Mo = (B) (24) (Days/Month)

E. Lb Disodium Phosphate/Mo = (C) (24) (Days/Month)

The boiler chemical cost is then estimated by summing the monthly chemical usage and multiplying by the cost of the chemicals. Water-treating chemical usage is divided into two categories: (1) water treatment system and (2) deaerator or oxygen scavenger system. The oxygen scavenger system is based on the deaerator reducing the oxygen

in the feedwater to a level of 0.005 ppm, and the scavenger chemical (hydrazine) removing the remaining oxygen from the water. The monthly hydrazine level usage is estimated by:

Hydrazine Usage - lb/mo = ([5/1 x 108][Average Month Steam Flow - Lb/Hr][1 + % Blowdown Flow/100][1.5][24Hrs/Day][Days/Month]

Summing the months provides the hydrazine usage in pounds per year. Multiplying this by hydrazine cost (in dollars per pound) estimates the yearly cost of the hydrazine. The water treatment chemicals are dependent on the type of system and the number of regenerations. The zeolite system uses salt; demineralizer systems (as well as mixed-bed and condensate polishers) use acid and caustic.

Zeolite system salt usage is estimated by:

NaCl - lb/yr = [6][Resin Vessel Area][Resin Depth][Number of Regenerations /Year]

Demineralizer systems chemical usage is estimated by:

Acid - lb/yr = (Cation Vessel Acid per Regeneration) (Number of Regenerations/ Year) / (15.4)

Caustic - lb/yr = (Anion Vessel Caustic per Regeneration) (Number of Regenerations/Year) / (12.8)

Chemical usage for the mixed-bed and condensate polisher is estimated by:

Acid - lb/yr = (Mixed-Bed Vessel Acid per Regeneration) (Number of Regenerations/Year) / (15.4) Caustic - lb/Yr = (Mixed-Bed Vessel Caustic per Regeneration) (Number of Regenerations/Year) / (12.8)

The chemical costs per year are then determined by multiplying the chemical cost (per pound) by the total chemical usage (in pounds) per year. The cooling tower chemicals consist mainly of chlorine and a periodic shock treatment of another biocide. The chlorine usage is estimated by:

Chlorine Usage - lb/yr = [15/1 x 108][Circulating Water Flow] [60][8.33] [1.5][365] [0.90][1.25]

The chlorine cost is then determined by multiplying the chlorine usage times the cost of chlorine (escalated). The other biocide cost is estimated as 1.75 times the cost of chlorine, and the total cooling tower chemical cost is estimated as 2.75 times the cost of chlorine.

Maintenance Parts

Maintenance parts are estimated as a function of plant size. The yearly spare parts cost is estimated as 85 percent of the spare part capital cost. During the first year of operation, this cost is estimated as 15 percent of spare parts.

Facility Consumables

The consumable costs estimate is the same as calculated in the capital costs. During the first year of operation this cost is estimated as 20 percent of consumable costs.

Facility Grounds Maintenance

This category is for the area or grounds maintenance, which includes such things as cutting the grass, road repair, railroad track maintenance, etc. This cost is estimated as a function of plant area acreage, and is provided by:

Cost - $/Yr. = [$7500/Yr][Plant Acres] [1 + % Labor Escalation/100][Labor Productivity][Labor Cost - $/Hr/12]

where: L =1988 Labor Cost - $/Hr is the costof labor, including fringe benefits, profit, and overhead of an outside contractor.

Labor cost is estimated at $12.00/hr (State of Ohio, 1988 dollars.

Insurance

This category is for general facility insurance and, for third-party financing, operation and potentially bond insurance. The general facility insurance is estimated as 0.05 percent of the capital equipment plus building cost of the facility escalated every 3 years. The bond insurance cost is estimated as 0.08 percent of the bonded cost of the facility. The bonded cost of the facility is conceptually estimated as total capital cost of the facility multiplied by 1.33.

Mobile Equipment

This category is for maintaining the facility's mobile equipment. The cost is estimated as 8 percent of the mobile equipment capital cost (escalated).

Stack

The stack cost is for an outside contractor to maintain the lights (FAA and beacon), and for an annual inspection. The cost is estimated as:

Cost - $/Yr. = [$12,000/Yr][1 + percent Labor Escalation/100][Labor Productivity Factor][Labor Cost - $/Hr/$20.00][Number of Stacks]

where: 1988 Labor Cost - $/Hr is the cost of labor, which includes fringe benefits, profit, and overhead of an outside contractor.

Labor cost is estimated at $20.00/hr (State of Ohio, 1988 dollars)

Steam Distribution Maintenance Parts

The steam distribution system's yearly spare parts and outside contracted services are estimated as a function of type of distribution system (e.g., tunnel, direct burial, etc.) and the capital cost of the system. The estimated cost of parts and outside services are provided by:

Cost - $/Yr.= [0.005][System's ConstructionCost][System Factor][1 + % Mat'l. Escalation/100]

where: System's Construction Cost is provided by Steam Distribution Costs.

System Factor is as follows:

Tunnel: = 1.1
Direct burial: = 1.6
Shallow trench: = 1.0
Aboveground: = 1.15

Major Maintenance

This category is for major equipment rebuilds, e.g., boiler, pulverizer, turbine-generator, baghouse rebagging, water treatment resin replacement, etc. Also included are the permit renewal fees and tests. The major maintenance cost categories are described below.

Boiler Maintenance

Each boiler will have yearly shutdowns to perform maintenance. The cost of these outages is estimated to be 0.70 percent of boiler capital cost. In addition to the yearly outages, the boilers will periodically experience extended shutdowns to replace or repair the boilers (e.g., superheater replacement, grate replacement, economizer repairs, safety valve repair, fan repairs, etc). These costs are used in lieu of an annual cost estimate,and are estimated to be 6 percent of the boiler capital cost occurring every 15 years.

Pulverizer Maintenance

The primary component of a coal pulverizer is the pulverizer mechanism itself, whether it be a ball-race mill, ring-roll mill (roller mill), or some other type. Because of the wear level, maintenance is estimated to consist of the replacement of the grinding components and maintenance to related elements once every 3 years. With each boiler having three pulverizers, this translates into one pulverizer per boiler being worked on every year. Meeting this requirement implies that running time is monitored for each pulverizer so the level of wear can be adjusted, ensuring that a second pulverizer will not require major maintenance at the same time as the first. In practice, actual wear may allow a more relaxed maintenance schedule. However, this schedule has been adopted because it represents the worst case.

The costs for replacing the grinding components and other maintenance for each pulverizer is based on the size of the boiler for the pulverizer, as follows:

$$\text{Pulverizer maint cost} = 0.24\ [\text{Boiler MCR, lb/hr}] + 28{,}000$$

Turbine-Generator Maintenance

The small, gear-type turbine-generator is estimated to have one outage every 8 years at a cost of 8 percent of the turbine-generator's capital cost. The large, 600 psig, 750 °F direct-drive turbine-generator is estimated to have an outage every 5 years at a cost of 10.5 percent of the turbine-generator's capital cost (escalated).

Baghouse Maintenance

The baghouse is estimated to have an outage every 3 years. This is mainly for bag replacement. The estimated cost is 5 percent of the capital cost of the baghouse (escalated). Every 12 years the estimated maintenance cost is 7 percent of the capital cost (escalated).

Cooling Tower Maintenance

The cooling tower is estimated to have an outage every 15 years for wood replacement, fan repairs, and fill replacement/cleaning. The cost of this is estimated as 10 percent of the capital cost of the cooling tower (escalated).

Pumps

Motor-Driven FW Pumps. These pumps are estimated to require rebuilding every 15 years at an estimated cost of 40 percent of the pump's capital cost.

Turbine-Driven FW Pumps. These pumps and turbines are estimated to be rebuilt every 12 years at an estimated cost of 60 percent of the pump's capital cost.

Other Centrifugal Pumps. These pumps are estimated to require rebuilding every 18 years at an estimated cost of 40 percent of the capital cost.

Sump Pumps. These pumps are estimated to require rebuilding every 20 years at an estimated cost of 35 percent of the capital cost.

Circulation Water Pumps. These pumps are estimated to require rebuilding every 25 years at an estimated cost of 25 percent of the capital cost.

Deaerator

The deaerator is estimated to have a major outage for internal parts replacement every 20 years. The estimated cost is 25 percent of the capital cost.

Conveyor Systems

Coal. The coal system is estimated to have the following equipment rebuilt at the time periods provided:

- Bucket elevators: 38 percent of capital cost every 8 years
- Coal crusher: 20 percent of capital cost every 10 years
- Conveyor belts: 5 percent of capital cost every 15 years

Lime. The lime systems are estimated to be 3 percent of the capital cost (escalated) every 5 years.

Ash. The ash system estimate is based on rebuilding the system every 7 years at a cost of 22 percent of the capital cost (escalated).

Water Treatment System

This system is estimated to have a major shutdown every 10 years for valve repairs, tank relining, and resin replacement. The estimated cost is 45 percent of the capital cost.

Stack

The stack is estimated to require major repair every 20 years. The estimated cost is 1 percent of capital cost.

Lime System Dry Scrubber

This equipment is estimated to require major repairs (e.g., atomizer rebuilds, slaker rebuilds, lime pump rebuilds, etc.) every 5 years. The estimated cost is 6 percent of the capital cost of the lime system dry scrubber.

Building

The building is estimated to require a new roof, painting, etc., every 20 years. The estimated cost is 15 percent of the capital cost.

Fans

This estimated cost is for the ID fans only. Other fan repair/rebuild costs are included with the main equipment item served by the fan. For example, FD fans are included

in the boiler estimated repair costs, and building vent fans are included in the building estimated repair costs. The ID fans are estimated for overhaul every 20 years. The cost estimate is 38 percent of the capital cost.

Permits

This category is to estimate the required periodic EPA permit testing and renewal costs. The cost is estimated to be $30,000 (1988 dollars) every 3 years.

7 Summary and Recommendation

This report documents the algorithms and logic supporting models for screening and costing new pulverized-coal-fired central heating plants for military installations. The models are available to users in a computer-based implementation—the pulverized-coal module to the USACERL-developed Central Heating Plant Economic Evaluation System (CHPECON).

Although pulverized coal boilers are not now widely used on Army facilities, several U.S. Navy bases have central energy plants fueled with pulverized coal. Integration of the pulverized-coal option into CHPECON was desirable to cover all combustion technologies used in DOD central energy facilities.

Due to continuous advances in boiler plant technology and the changing nature of the fuel markets, it is recommended that the user frequently update the cost algorithms.

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Abbreviations and Acronyms

ABMA	American Boiler Manufacturers Association
ACFM	actual cubic feet per minute
ACS(IM)	Assistant Chief of Staff for Installation Management
ASME	American Society of Mechanical Engineers
BFWP	boiler feedwater pump
BHp	brake horsepower
CF	cubic feet
CHPECON	Central Heating Plant Economic Evaluation Program
CEMS	continuous emissions monitoring system
DCF	discounted cash flow
DOD	Department of Defense
EPA	U.S. Environmental Protection Agency
FAA	Federal Aviation Administration
FD	forced-draft (fan)
FGD	flue gas desulfurization
FW	feedwater
gpm	gallons per minute
Gr	grain
HHV	higher heating value
HTHW	high-temperature hot water
HVAC	heating, ventilating, and air conditioning
ID	induced-draft (fan)
LCC	life-cycle cost

MCR	maximum continuous rating
mph	miles per hour
NOx	nitrogen oxide(s)
NSPS	New Source Performance Standards
NTU	nephelometric turbidity unit
O&M	operation and maintenance
PABX	private automatic branch exchange
pph	pounds per hour (of steam)
psig	pounds per square inch gage
PMCR	plant maximum continuous rating
PWTB	Public Works Technical Bulletin
SJAE	steam jet air ejector
SOx	sulfur oxide(s)
TCV	temperature of critical viscosity
TDS	total dissolved solids
TM	Technical Manual
tpd	tons per day
tph	tons per hour
USACERL	U.S. Army Construction Engineering Research Laboratories
USAREUR	U.S. Army, Europe

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